Regulatory Finance Issues – Response to RIIO-2 Framework Document

A Report for SGN

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Contents

Executive Summary

SGN commissioned NERA Economic Consulting (NERA) to provide a report addressing a number of regulatory financial issues raised by Ofgem in its recent framework consultation for the next RIIO price control (RIIO-2). We were asked to consider Ofgem's options on setting the cost of debt allowance; cost of equity indexation; financeability; and, ensuring fair returns. We have also undertaken analysis in relation to the relative risk of SGN over GD2.

Cost of debt indexation (Chapter 2)

At RIIO-GD1 and RIIO-T1, Ofgem adopted a cost of debt indexation mechanism based on average of the A and BBB iBoxx indexes of the yields on GBP non-financial corporate debt of 10 years + remaining maturity, and a trailing average of 10 years. The nominal iBoxx index is deflated using the break-even inflation implied by the difference between nominal and index linked 10 year gilt yields for the relevant index date. At RIIO-ED1, Ofgem adopted the so-called trombone index which has a starting trailing average of 10 years but which extends by one year by fixing the start year, until the trailing average extends to 20 years.

In the framework consultation, Ofgem invites views on its approach to compensating companies for efficient debt costs at RIIO-2. Ofgem states that the relevant policy objectives and principles should be to: ensure that consumers pay no more than an efficient cost of debt; the cost of debt should be a reasonable estimate of the actual cost of debt for a notionally geared efficient company; should provide incentives to minimise debt costs; and, the calculation should be simple and transparent. It consults on three options for setting the cost of debt:

- Option A: to recalibrate the RIIO-1 indexation policy
- Option B: A fixed allowance for existing debt plus indexation for new debt only
- Option C: pass-through allowance for debt.

We have considered in detail the required changes to the GD1 mechanism, notably in relation to the trailing average, allowance for transaction costs, and approach to inflation. We conclude a re-calibrated GD1 mechanism is most likely to meet Ofgem's objectives assuming these aspects issues are addressed correctly.

A 10Y trailing average will not allow cost-recovery; 20Y is conceptually correct

Our analysis shows that the current RIIO-GD1 10 year average and the ED1 trombone mechanisms do not allow for SGN or the wider industry (excluding Cadent) to recover debt costs over GD2 under a range of plausible interest rate scenarios, and therefore fails to meet Ofgem's criteria of allowing companies to recover efficient debt costs. Cadent's debt issuance costs should be excluded from the analysis to inform the re-calibration of GD1 mechanism given its recent refinancing following the sale by NG, and its atypical debt profile and costs.

Both the current mechanism and trombone, both drawing on a 10 year starting trailing average, exclude a substantive element of SGN and industry historical debt issuance, and therefore the mechanisms do not provide a reasonable estimate of the cost of debt for an efficiently financed network.

We show that the conceptually correct trailing average is 20 years, in line with the efficient tenor at issuance of debt for energy networks, and therefore better captures historical debt issuance. However, we consider that a trailing average that starts at 15 years, and therefore reflects the actual period over which GDNs have issued debt since DN sales in 2005, is reasonable in this context. The use of a 15 year period, extending by one year throughout GD2 until the conceptually correct trailing average of 20 years is achieved, would then ensure the trailing average accurately reflects the period over which GDNs had outstanding debt. Our analysis also suggests that a starting trailing average of 15 years provides that in expectation SGN (and the wider industry) recovers its efficient debt costs.

There is no evidence of a regulatory halo: t-costs should be allowed in full

Ofgem has also consulted on using the iBoxx A rated Corporate bond index, and/or a downward adjustment to the iBoxx index to take into account supposed energy network outperformance (“regulatory halo”) over RIIO-1. At RIIO-1, Ofgem did not allow for networks to recover debt issuance costs that it estimated at 20 bps based on its assumption that networks could meet these costs through outperformance of the benchmark index.

We have analysed energy company debt issuance costs relative to the benchmark index. Our analysis shows that the alleged outperformance is a result of a failure to consider energy company debt with the iBoxx benchmark on a like-for-like basis. Specifically, we show that CEPA’s analysis of outperformance incorrectly uses the coupon as opposed to yield-at-issuance as the measure of debt cost, and fails to correctly account for the higher rating at issuance of energy network bonds and the A and BBB rated iBoxx indices. Once we control for these errors, our analysis shows that there is no evidence for energy company outperformance and as a consequence Ofgem should allow transaction costs in full.

The use of break-even inflation does not allow energy networks to recover costs

We have set out options for the derivation of a real cost of debt from the nominally observed iBoxx benchmark, including under a switch to CPI indexation. The options are to use the current break-even approach plus an estimate of the CPI-RPI wedge; an ex-ante inflation assumption (as per Ofwat’s proposed approach and UR in NI); or, the outturn inflation rate applied to RAV.

We show that break-even inflation is likely to overstate inflation and understate real debt costs; the use of 20 year break-even is particularly problematic given the illiquidity in long-dated IL gilts. Current evidence suggests that the 20 year break-even overstates long run inflation by around 30-40 bps. Our preferred approach to derive the real cost of debt allowance is to use a measure of the outturn inflation rate that is applied to the RCV, as this should ensure that investors recover nominal debt costs.

There is a potential downside from using outturn inflation: in any one year outturn inflation may differ substantively from the implied inflation in nominal debt costs (which will reflect inflation expectations over the period of the debt). The resulting volatility in the allowed real cost of debt component of revenues could potentially be avoided by using an average inflation measure calculated over a number of years.

A well designed index will better meet Ofgem's objectives than options B & C

We consider that both option B, a fixed embedded cost of debt allowance based on the industry average with new debt costs compensated by an index, and option C, a cost of debt pass-through, are less likely to meet Ofgem's objectives than a correctly re-calibrated GD1 mechanism (option A). Both options B and C are likely to be more costly and intrusive as they require an investigation of companies' actual costs, and may blunt incentives to minimise debt costs notably in relation to option C.

However, the relative merits of the different options may be reversed if the GD1 mechanism is poorly calibrated and does not allow companies to recover efficient costs.

Cost of equity indexation (Chapter 3)

Ofgem has proposed a cost of equity indexation approach for RIIO-2 where the cost of equity is updated annually to reflect market movements. In considering cost of equity indexation, CEPA, Ofgem's consultant, has identified three broad options:

- Index risk-free rate only
- Index risk-free rate (RfR) with offsetting adjustment for the ERP
- Index the TMR, and RFR (a so-called "TMR approach")

Overall, we do not consider that Ofgem has made the case for equity indexation

Our analysis suggests that there is not a strong case for indexation. As with other uncertainty mechanisms, indexation should be used where costs are uncertain such that it is difficult to set a reasonable ex ante allowance, e.g. as with the cost of debt. This is not the case for the cost of equity given the constancy of the TMR over time, as acknowledged by Ofgem and CMA in setting the cost of capital.

Indeed, Ofgem's own proposed mechanism, which proposes to change the allowed return on equity by "(1-beta)*RFR", involves practically no change to the cost of equity allowance where the beta is close to 1 as at RIIO-1. Therefore, we consider that there is a strong case for setting an ex-ante allowed return on equity as per all previous reviews, and in common with all other GB regulators. The potential adoption of a shorter 5 year price control also means it is unnecessary to adopt an indexation mechanism.

By contrast, an indexation mechanism would complicate the price control process unnecessarily and contradicts Ofgem's intention to simplify arrangements. Finally, we note that if an indexation approach were implemented, the long-run historical TMR data may provide an objective measure of the cost of equity and the potential basis for an index, but the specific index and its interpretation (e.g. in terms of averaging techniques) will need to be clearly specified in advance.

Financeability (Chapter 4)

In its framework consultation, Ofgem states that it has a duty to have regard to companies' ability to finance their activities. Ofgem states that at previous reviews it has assessed whether companies can maintain an investment grade credit rating drawing on rating agencies' methodologies, and confirms that it intends to undertake a similar approach at RIIO-2.

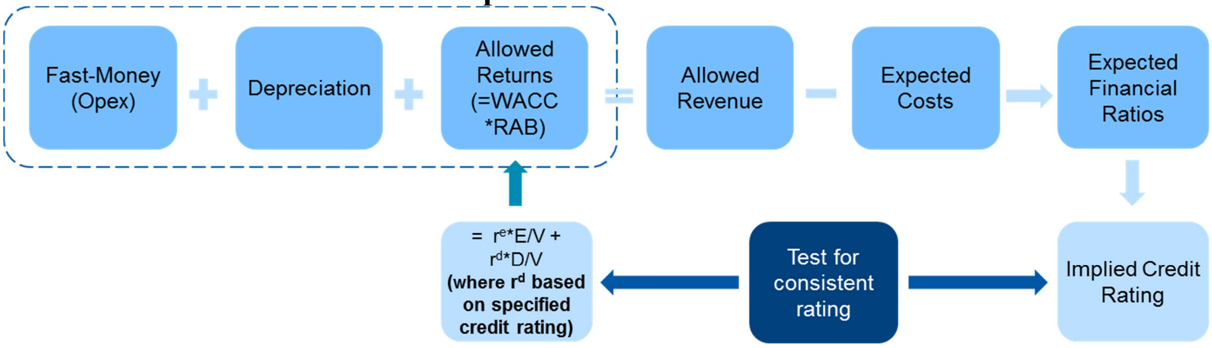
However, it also notes that its proposed cost of equity and a declining cost of debt allowance is likely to lead to a lower overall baseline return at RIIO-2 which will make it more challenging to meet the standard financeability metrics which may deteriorate. Ofgem is consulting on three policy options for addressing financeability issues:

- Option A: Adopting a nominal return instead of a real return which will bring cash-flows forward
- Option B: Putting the onus on companies, e.g. to de-gear, and/or changes to regulatory levers to bring forward cash-flows
- Option C: Introducing a licence backed revenue floor

Onus should be on Ofgem to ensure consistency of its financial proposals

We have reviewed Ofgem's proposed approach and three options. The financeability test is a test of consistency between the rating underpinning the allowed rate of return and the rating implied by the forecast financial metrics. If the financial metrics provide a credit rating below an average of A and BBB, then the onus should be on Ofgem to reconsider the cost of equity and the rating of the index underpinning the cost of debt mechanism.

Figure 1
The financeability test should test consistency between the allowed rate of return and the expected financial metrics



Source: NERA illustration

As Ofgem acknowledges, short-term fixes, e.g. bringing forward cash-flows as under option B, do not resolve the underlying issue and will simply defer financeability issues to subsequent review periods. In addition, any arbitrary changes to regulatory levers (e.g. capitalisation rates) may not be recognised by rating agencies, and therefore may not result in improvements to financial metrics.

Ofgem's other proposed fix, moving to a nominal WACC (option A), represents a fundamental change to the existing regulatory framework and should be assessed in a wider policy context than purely considering financeability implications including higher short-term bills and inter-generational equity.

In relation to option C, Ofgem proposes to provide minimum debt cover based on notional capital structure and notional cost of debt. Ofgem also intends that any advanced revenues are recovered over future years: the approach simply defers financeability issues to subsequent years. The approach will also require greater regulatory cost, in contrast to Ofgem's intention to simplify the regulatory framework.

Ensuring fair returns (Chapter 5)

In its framework document, Ofgem consults on a number of potential changes aimed at ensuring fair returns to energy networks. In particular, Ofgem expresses concern that returns have been high in the gas distribution and electricity transmission sectors, where the main driver has been cost outperformance. In the electricity distribution sector, it notes that performance against the interruptions incentive provides the main driver. Ofgem identifies a number of measures that could guard against higher returns, comprising:[1]

- A hard cap/floor
- Discretionary adjustments
- Constraining totex and output incentives
- A RoRE sharing factor
- Anchoring returns

Relatively high returns are a consequence of GDNs bearing market risks

We have analysed the level and sources of outperformance at RIIO-1 in comparison with the water and other partially regulated sectors. We show that the variation and level of returns for the GDNs and wider set of energy networks is not unreasonable or unexpected relative to the variation in the regulated water sector and comparable partially-regulated sectors such as telecoms and transport.

GDNs' cost performance can be explained by both improvements in cost efficiency relative to assumptions at review, as well as the consequence of the risks, notably input price risks, borne by GDNs during the review period. The weak economic recovery, and fall in commodity prices, has led to input price growth below those assumptions made at review.

Any changes to the framework should preserve efficiency properties of RIIO

We consider that any changes to the RIIO framework should focus on rebalancing the risks borne by GDNs relative to customers, whilst preserving the incentive properties of the RIIO framework to ensure continued strong performance on cost efficiency. There are three areas that Ofgem could consider in terms of rebalancing risk, and mitigating the scope for future out (and under) performance from these market risks. These are RPE indexation; sculpting the incentive rate; and, a shorter price control. Ofgem is consulting on all three measures,

[1] Ofgem (March 2018) op. cit., para 7.122,.p. 103

and has stated its intention to adopt cost indexation where feasible, and a shorter price control review.

We consider that RPE indexation could address concerns around high returns whilst preserving the strong incentive properties of the RIIO framework, although the feasibility of this approach depends on the availability of reliable and reputable indices that accurately track energy networks' costs. We also consider that sculpting incentive rates, i.e. a moderated incentive rate as the realised return moves away from the baseline return, could improve legitimacy of the regime, assuming that the incentive rate is not set so low that it diminishes incentives for improvements in cost and output performance. The requirement for sculpting also depends on Ofgem's other decisions, e.g. it may not be required if the price control is shortened to 5 years.

By contrast, we consider that Ofgem's options 1 (hard cap/floor), option 2 (discretionary adjustments), aspects of option 3, and option 5 (anchoring returns) are neither necessary to ensure fair returns, nor desirable from a customer interest perspective given the likelihood that they will increase risk and/or blunt incentives to improve cost and output performance. Our other proposed options that use existing regulatory tools, e.g. a shorter price control period, sculpting sharing factors, and RPE indexation, also obviate the need for these mechanisms.

The RIIO-2 framework should focus on those output and customer service measures that customers care about. Our comparison of the scope for rewards and penalties relative to other sectors shows that the incentive framework is modest relative to other sectors and should be enhanced at RIIO-2.

Overall, the RIIO framework has worked well in incentivising companies to minimise costs, which are ultimately passed through to customers. By removing market risk, e.g. through RPE indexing, and enhancing output incentives, energy networks' financial performance would be more clearly aligned with cost efficiency and output performance.

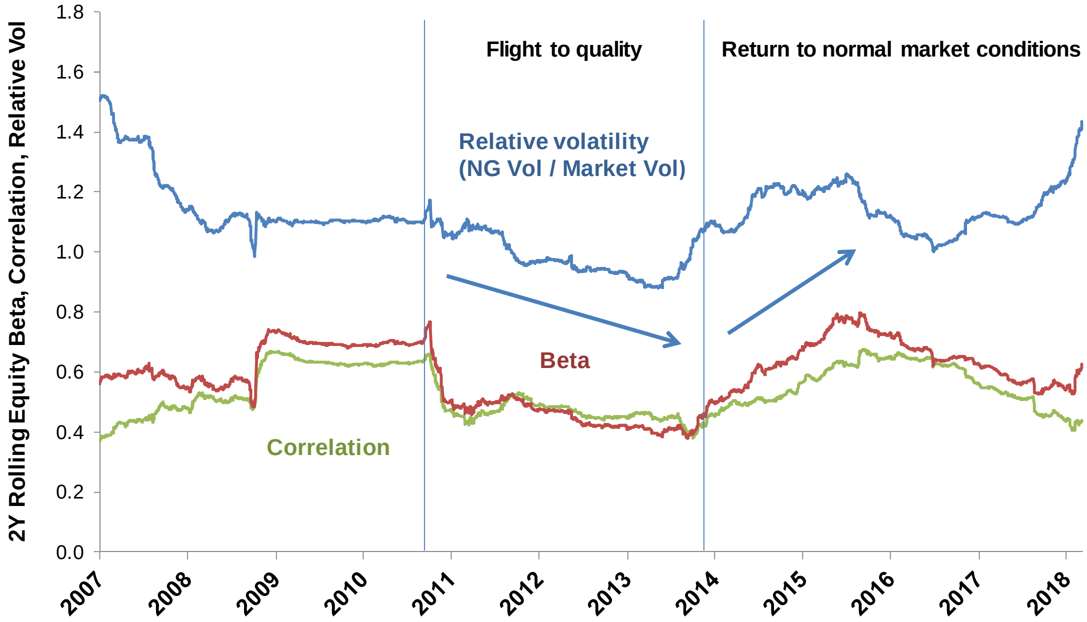
Relative Risk (Chapter 6)

We have considered empirical beta estimates for UK and European networks, as well as considered the specific risks faces by investors in SGN.

UK and European empirical evidence supports an asset beta of at least 0.4

Our analysis of UK listed network companies – NG plc, United Utilities, Severn Trent, and Pennon – show that the majority of beta estimates lie in the range of 0.3 to 0.4, with values for energy networks towards the top-end of this range, i.e. NG plc's two-year asset beta is 0.37. Comparator listed network betas have been returning back to "normal" (pre-GFC) levels as the constituent elements of beta risk – correlation with the market and relative (absolute) risk – are trending back to normal levels.

Figure 2
Increase in NG plc’s beta since RIIO-1 largely explained by increase in relative volatility



Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: FTSE All Share.

NG plc’s composite beta understates the risk associated with GB energy networks assets, given its ownership of lower risk US networks. NG plc’s composite beta reflects the combined systematic riskiness of NG plc’s UK and US operations, and empirical evidence shows that US operations are lower risk with assets betas of around 0.25. Decomposing NG plc’s beta, we obtain a range of 0.43 to 0.47 for NG plc’s UK beta.

As well as UK empirical beta estimates, we have estimated asset betas for listed European networks operating in Italy and Spain. The empirical evidence supports an asset beta of around 0.4 over the most recent 2 year period. Our comparative risk assessment of the Italian and Spanish regimes suggests that investors face broadly similar risks as per GB energy networks, and therefore 0.4 asset beta provides a relevant benchmark for GB energy networks.

Overall, the empirical analysis, as evidenced by the decomposition of NG plc’s beta in comparison to listed GB water network betas, demonstrate that investors in energy networks face greater risks.

Our qualitative risk assessment shows that SGN faces greater risks than most other networks from asset stranding risk, given the uncertainty over government policy and technological solutions to the decarbonisation of heat. Our review of European regulatory decisions indicates an uplift to asset beta of 0.06 to compensate for such risks. SGN also faces greater exposure to operational leverage, as measured by the return and depreciation elements as a proportion of revenues, the principal measure adopted by the CMA.

1. Introduction

SGN commissioned NERA to provide a report addressing a number of regulatory financial issues raised in Ofgem's recent framework consultation for the next RIIO price control (RIIO-2).[2] We were asked to consider options around setting the cost of debt allowance; cost of equity indexation; financeability; ensuring fair returns; and, relative risk of SGN.

The report is structured as follows:

- Section 2 assesses Ofgem's options for setting the cost of debt allowance at RIIO-2
- Section 3 assesses Ofgem's options for cost of equity indexation
- Section 4 responds to Ofgem's proposed approach for ensuring financeability
- Section 5 responds to Ofgem's proposals on ensuring fair returns.
- Section 6 sets out our views on a fair remuneration for equity risk at RIIO-2, providing empirical beta analysis and an assessment of SGN specific risks

2 Ofgem (March 2018) Framework Consultation. Link: https://www.ofgem.gov.uk/system/files/docs/2018/03/riio2_march_consultation_document_final_v1.pdf

2. Setting Cost of Debt Allowance

In the framework consultation, Ofgem invites views on its approach to compensating companies for efficient debt costs.

Ofgem states that the relevant policy objectives and principles should be to: ensure that consumers pay no more than an efficient cost of debt; the cost of debt should be a reasonable estimate of the actual cost of debt for a notionally geared efficient company; should provide incentives to minimise debt costs; and, the calculation should be simple and transparent.[3]

It then goes on to consult on three options for setting the cost of debt:

- Option A: to recalibrate the RIIO-1 indexation policy
- Option B: A fixed allowance for existing debt plus indexation for new debt only
- Option C: pass-through allowance for debt.

The focus of our response is around the recalibration of the RIIO-1 index under option A. We conclude that if correctly recalibrated option A should best achieve Ofgem's policy objectives. The changes include extension of the starting trailing average towards the conceptually correct 20 year trailing average and recognition of transaction costs, and consideration of the use of outturn inflation (as used to index the RAV) to derive a real allowance.

2.1. Optimal re-calibration of RIIO-1 index (option A)

At RIIO-GD and RIIO-T1, Ofgem adopted a cost of debt indexation mechanism based on average of the A and BBB iBoxx indexes of the yields on GBP non-financial corporate debt of 10 years + remaining maturity, and a trailing average of 10 years. The nominal iBoxx index is deflated using the break-even inflation implied by the difference between nominal and index linked 10 year gilt yields for the relevant index date.[4]

At RIIO-2, Ofgem invites views on the following design aspects:[5]

- Moving to a shorter or longer trailing average, e.g. 20 years as per ED1 "trombone"
- Using an A rated benchmark
- Weighting the index for individual companies according to RAV growth to better reflect timing of debt issuance
- Taking into account the alleged ability of companies to issue at lower rates than the benchmark indices

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3 Ofgem (March 2018) op. cit., p. 78

4 Ofgem (2014) RIIO-ED1: Draft determinations for the slow-track electricity distribution companies Financial Issues, p. 11. Link: https://www.ofgem.gov.uk/sites/default/files/docs/2014/07/riio-ed1_draft_determination_financial_issues.pdf

5 Ofgem (March 2018) op. cit., p. 80

We consider these issues in the following sections.

2.2. Option A – Optimal trailing average

2.2.1. The conceptually correct approach is to match trailing average to efficient average tenor at issuance

2.2.1.1. The selection of the benchmark index should reflect the efficient tenor at issuance

In selecting the benchmark index the average *remaining tenor* of the benchmark index should match the average *tenor at issuance* of network companies' debt. The reason why the *remaining tenor* of the index must reflect the average tenor at issuance is because the cost of debt *allowance* is set equal to the yield-to-maturity of the benchmark iBoxx index whereas the *actual cost* (the coupon) is equal to its own yield-at-issuance. For the allowance to equal the expected debt cost, the *remaining tenor* of the benchmark index has to match the average *tenor at issuance* of network companies' debt.

As acknowledged by Ofgem at RIIO-1, the selected benchmark index (iBoxx Corporate 10Y+) has a remaining tenor which approximates to the average tenor at issuance of network companies' debt of around 20 years. Ofgem noted that its benchmark iBoxx index has a remaining maturity which is "*broadly in line*" with the tenor at issuance of network companies' debt, and that "*the iBoxx indices have the advantage of including bonds of longer than ten years maturity, thus better capturing the debt profiles of network companies.*" [6]

Evidence on wider energy network tenors presented at ED1 and our own updated analysis of GDN bond issuance shows that the average tenor at issuance remains broadly around 20 years, and thus supports the continued use of the iBoxx 10Y+ index which has an average remaining tenor of around 20 years. [7]

2.2.1.2. The choice of trailing average should be based on the efficient tenor at issuance, as implied by the benchmark

Once the benchmark index is selected, the trailing average period of the cost of debt indexation mechanism should be set equal to the average remaining tenor of the bonds in the benchmark index (which in turn has been selected to reflect the average tenor at issuance of network companies' debt). By doing so, an energy network that issues a bond with a tenor of 20 years will receive an allowance equal to the efficient cost of the bond in each year of the lifetime of the bond, thus creating a reasonable prospect of recovering its debt costs.

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[6] Ofgem (March 2011): Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues, para. 3.34; https://www.ofgem.gov.uk/ofgem-publications/48262/gd1decisionfinance.pdf

[7] See footnote 8 for evidence provided as part of RIIO-ED1. For GDNs, we calculate the average tenor at issuance of 19 years for all outstanding bonds as of January 2018.

At ED1, the DNOs noted that a 10-year trailing average was significantly too short compared to the actual tenor at issuance of DNO debt of about 21 years.[8] The DNOs proposed that the conceptually correct trailing average would be 20 years as the starting average, although limitations on the iBoxx series limited the starting average in practice to 15 years for ED1.[9] Ultimately at ED1, Ofgem adopted the so-called trombone, with a starting average of 10 years and extending by one year until the trailing average achieves a 20 year period.

At GD1 and T1, Ofgem determined a 10Y trailing average. However, the relevant iBoxx indices were only available from 1998-99[10], which placed a limit on the trailing average at that time. In addition, a substantive element of industry debt (and all SGN debt) was issued post distribution network (DN) sales in 2005, and therefore the then 10Y trailing average captured the period of debt GDN debt issuance.[11]

2.2.2. SGN and industry cost performance under current 10Y trailing average, trombone, and 20 Y trailing average

We have modelled SGN and industry cost performance under different interest rate assumptions and index trailing averages.[12] In particular, we model SGN performance under three interest rate scenarios: 0, 2 and 4 per cent real iBoxx by the end of the period.

Our analysis shows that SGN will materially under-recover debt costs over GD2 under the current mechanism, as will the wider industry where we exclude Cadent from the analysis. We consider that Cadent should be excluded from the analysis to inform the re-calibration of the GD1 mechanism, given its atypical debt profile and low embedded debt cost following its recent refinancing upon the sale by National Grid.[13]

We have also modelled SGN and the wider industry performance under an ED1 trombone.[14] Our analysis suggests that SGN's also materially under-recover debt costs, as does the wider industry excluding Cadent, i.e. an ED1 trombone does not allow for the recovery of efficient debt costs.

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8 See Ofgem (30 July 2014): RIIO-ED1: Draft Determination for the slow-track electricity distribution companies – Financial Issues, para 2.36; https://www.ofgem.gov.uk/ofgem-publications/89072/riio-ed1draftdeterminationfinancialissues.pdf

9 NERA (26 September 2014): A Response to Ofgem's Proposals on the Cost of Equity and Debt for RIIO-ED1, p. ii

10 The iBoxx GBP Benchmark Index was published on 1997/12/31, and the yield on the index start on 1998/1/1. See IHS Markit iBoxx GBP benchmark documentation, p.18.

11 From 2016/17 onwards, the 10 year trailing average no longer captured all post DN sales debt issuances.

12 We have modelled SGN and the industry cost of debt performance assuming an 8 year price control period for consistency with the current price control arrangements.

13 Ofgem as well as other regulators have designed bespoke mechanisms for networks with atypical profiles, as we discuss in section 2.3.

14 We assume the starting allowance for the first year of the RIIO-GD2 price control (the year 2021/2022, starting April 2021) would be based on the iBoxx index for the period 1 November 2010 to 30 October 2020. We then assume that the start date of the trailing average period is fixed such that the trailing average extends by one year for each year of the RIIO-GD2 price control, and into the next price control period, until the trailing average reaches 20 years for the regulator year 2031/2032.

We have also considered the cost of debt performance under a trailing average of 20 years from the start of the GD2 period.[15] Our analysis shows that a 20 year trailing average from the start, which is the conceptually correct trailing average, allows SGN and the wider industry to recover costs.

2.2.3. Conclusions on the optimal trailing average

The optimal starting point trailing average is 20 years, in line with the efficient tenor at issuance. However, we consider that a trailing average that starts at 15 years, and reflects the actual period over which GDNs have issued debt since DN sales in 2005, provides a reasonable approach in this context. The use of a 15 year period, extending by one year throughout GD2 until the conceptually correct trailing average of 20 years is achieved, would then ensure the trailing average accurately reflects the period over which GDNs had outstanding debt.[16]

Our analysis also suggests that a starting trailing average of 15 years provides that in expectation SGN (and the wider industry) recovers debt costs, and therefore meets Ofgem's own criteria.

2.3. Option A: A weighted index and/or bespoke mechanisms may be required for atypical networks

Ofgem also intends to consult on whether the index should be weighted according to RAV growth which it states may better reflect the timing of debt issuance. In the case of SGN, new debt issuance over GD2 will be primarily driven by refinancing of existing debt rather than RAV growth per se, which means that there is no advantage to weighting index years based on RAV growth. However, a weighted index may be required in specific cases where there is substantive RAV growth, as per the Scottish TOs at RIIO-T1.

More generally, bespoke mechanisms may be required for companies with atypical debt profiles, to ensure that the mechanism meets Ofgem's objectives, as we describe below. For example, UK regulators, including Ofgem, Ofwat and UREGNI have introduced approaches to the cost of debt that reflect actual debt issuance profiles where a company has an atypical profile, e.g. because of the lumpy debt issuance in the case of NI gas distribution, or the relative scale of the investment programme, in the case of SHETL and TTT.[17]

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[15] We assume the starting allowance for the first year of the RIIO-GD2 price control (the year 2021/2022, starting April 2021) would be based on the iBoxx index for the period 1 November 2000 to 30 October 2020.

[16] A 15 year starting trailing average for the first year of GD2 covers the period 2005-06 to 2019-20. A 20 year starting trailing average would cover the period 2000-01 to 2019-20.

[17] We describe these bespoke mechanisms in more detail in Appendix A

2.4. Option A: There is no evidence of a halo effect: t-costs should be allowed in full

Under option A, Ofgem states that it will consider using an A-rated benchmark rather than the average of A and BBB rated indices. It also states that it will consider how to take into account companies' alleged ability to issue debt at rates lower than the benchmark index.

In this section, we briefly review evidence on the so-called halo effect in relation to Ofgem's analysis at RIIO-ED1 energy price controls (i.e. Ofgem's most recent decision on this), the CMA's consideration of the halo effect at the recent British Gas Trading (BGT) appeal of RIIO-ED1 in 2015, and evidence provided by CEPA as part of the framework consultation.

We show that there is no evidence to support the halo-effect when a comparison of network debt issues and the benchmark index is undertaken on a like-for-like basis, and that the CMA confirms our view. The GD1 mechanism should be re-calibrated to allow for transaction costs in full.

2.4.1. Ofgem's so-called halo reflects sample bias

At RIIO-ED1 Strategy Decision, Ofgem compared the *yield at issue* of utility bonds with an average of A and BBB rated iBoxx indices and concluded that utilities can issue cheaper debt than the index. [18] However, our analysis shows that the so-called "halo effect" is almost entirely explained by:

- the inclusion of utility index-linked debt (ILD) which were significantly cheaper for a specific period of time, potentially driven by new regulations, [19] (see Figure 2.1); and
- the stronger rating of network companies' bonds which were predominantly A rated at issuance, compared to the benchmark average of the iBoxx 10Y+indices for A/BBB index.

Our analysis showed that correcting for these two errors results in a spread between the relevant iBoxx benchmark and the utility *yield at issue* of only 1 to 4 bps.[20]

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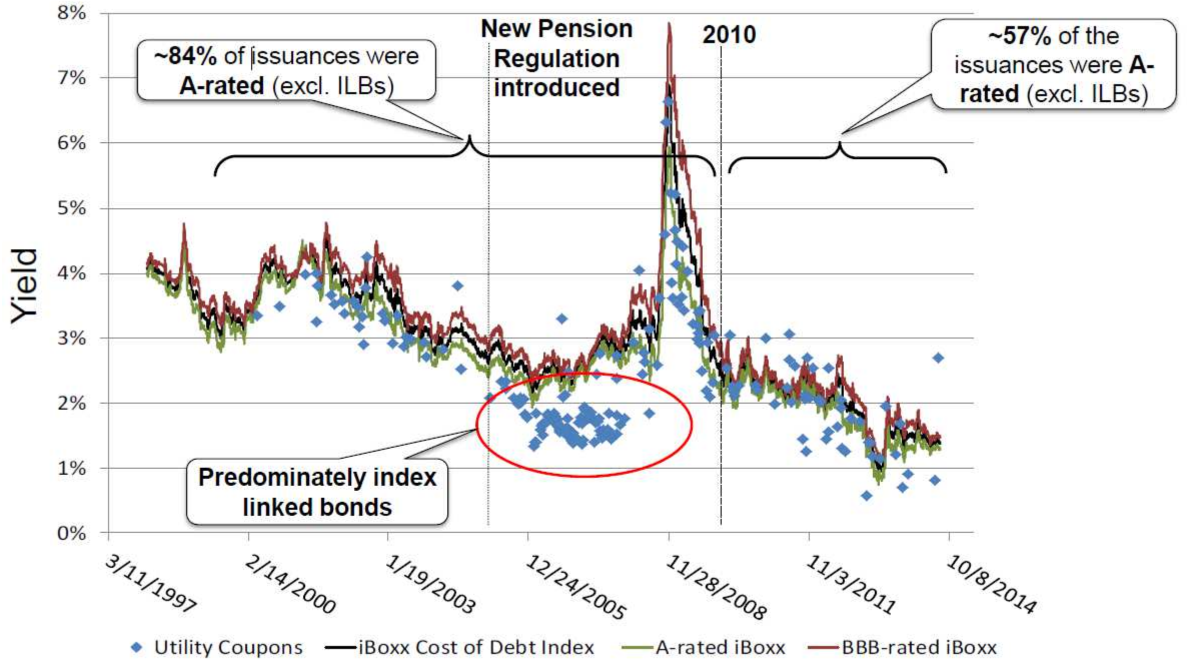
18 Ofgem (March 2013), RIIO-ED1 Strategy decision, p.12

19 The low yield of index-linked bonds was due to inelastic demand driven by the new pension regulation.

20 See for example reports commissioned by WPD, SPED and Energy Networks Association from NERA Economic Consulting over the course of RIIO-ED1. Links: http://www.westernpower.co.uk/docs/About-us/Stakeholder-information/Our-future-business-plan/Supporting-Financing-plan/NERA-Analysis-of-Ofgem-s-Halo-Effect.aspx; http://www.spenergynetworks.co.uk/userfiles/file/App12_201408_NERA_AnalysisOfOfgemCostOfDebtDraftDetRIIOED1.pdf.; http://www.spenergynetworks.co.uk/userfiles/file/App13_201409_NERA_ResponseToOfgemProposalsCoECoD.pdf

Figure 2.1
Ofgem's "halo effect" at ED1 was explained by ILD issues in 2005-2008, and stronger rating of utilities prior to the financial crisis



Source: NERA analysis of Ofgem data

At its Draft Determination for RIIO-ED1, Ofgem presented an alternative analysis on the halo effect to correct for the errors identified above. In its revised analysis, it compared the *yield to maturity* data (i.e. secondary market trading data) for DNO bonds and the iBoxx index, and concluded that DNO bonds' spread over UK gilts is systematically smaller than that of the iBoxx index. However, as with its earlier analysis, our analysis shows that the apparent halo effect reflected sample bias in the selection of companies' bonds, principally, that the remaining tenor of DNO bonds was systematically shorter than that of the index which results in a lower yield.

We show that controlling for the difference in tenor, and other effects[21], substantively eliminates the so-called "halo effect" (see Figure 2.2). Therefore, there is no evidence from secondary market debt trading that network yields' are lower than the iBoxx benchmark.[22]

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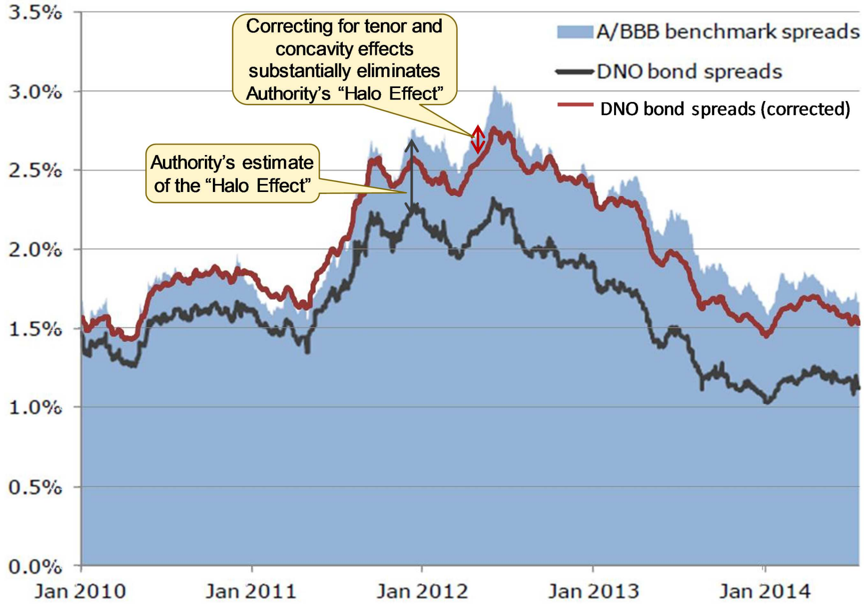
[21] For example, the concavity effect, which relates to the concave shape of the yield curve, i.e. that the yield increases as the tenor of the bonds increases, but at a decreasing rate. This means that the average yield of two bonds with a maturity of 5 years and 25 years is not the same, but in fact smaller than the yield on a 15-year bond (i.e. a bond with their average maturity). This thus implies that a portfolio of bonds with a high variability in the tenor of the composite bonds (e.g. the utilities bond portfolio), will have a lower average yield than a portfolio with a low variability (i.e. the iBoxx index), even if the bonds have the same average tenor.

[22] In its Consultation Framework, Ofgem indicates that it will examine secondary market data to assess scope for company outperformance of the iBoxx index. (See Ofgem (March 2018) RIIO-2 Framework Consultation, para 7.15.) The analysis undertaken at ED1 demonstrates that there is no evidence from trading yields to support a regulatory halo.

Figure 2.2
Ofgem's "Halo effect"is substantively eliminated once the comparison with the benchmark is made on a like-for-like basis



Source: NERA analysis. See *http://www.spenergynetworks.co.uk/userfiles/file/App13_201409_NERA_ResponseToOfgemProposalsCoECoD.pdf*

In its Final Determinations, Ofgem accepted that its analysis did not take account of differences in tenor.[23] Based on its revised analysis, it estimated a substantially reduced halo which it considered to be "*negligible*" for the substantive period of its analysis. [24]

2.4.2. CMA found halo effect substantively eliminated at ED1 appeal

The CMA also considered evidence on the halo effect as part of the appeal of Ofgem's RIIO-ED1 decision by British Gas Trading (BGT).[25] The CMA undertook its own analysis of the existence of the halo effect based on utility *yield at issue*. Although it found some evidence for the halo effect before 2009 (as shown by the blue line in Figure 2.3), the CMA noted that there was no evidence of a halo effect since 2009 (as shown by green line), and that any historical halo effect had diminished over time.[26]

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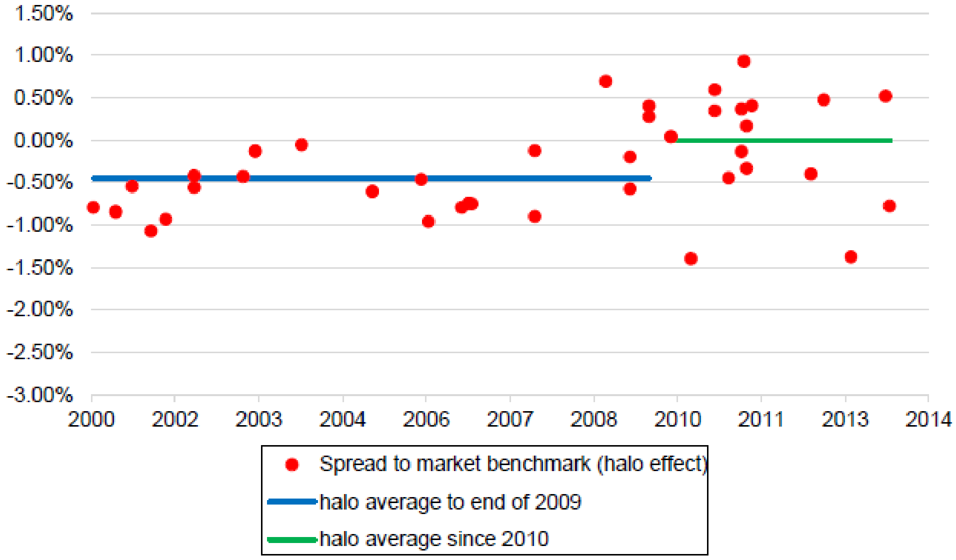
23 Ofgem (December 2014) Final Determinations – Overview, Appendix 8, para. 1.2; https://www.ofgem.gov.uk/ofgem-publications/92249/riio-ed1finaldeterminationoverview-updatedfrontcover.pdf

24 Ofgem (December 2014) Final Determinations – Overview, Appendix 8, para. 1.4; https://www.ofgem.gov.uk/ofgem-publications/92249/riio-ed1finaldeterminationoverview-updatedfrontcover.pdf

25 CMA (2015) British Gas Trading Limited v The Gas and Electricity Markets Authority, Figure 15, p.137, para 8.8 (c)

26 CMA (2015) British Gas Trading Limited v The Gas and Electricity Markets Authority, Figure 15, p.150

Figure 2.3
CMA found no evidence for halo for the period from 2010



Source: CMA (September 2015), CMA BGT vs GEMA Final determination, p.150

2.4.3. CEPA evidence of halo effect suffers from sample bias (similar to Ofgem RIIO-1 analysis)

In its February 2018 report for Ofgem, CEPA carries out an assessment of the halo effect considering a sample of GB regulated energy networks' bonds.[27] Based on a comparison between the coupons of energy networks bonds and the iBoxx A/BBB index, CEPA estimates an average halo effect of 38 bps for nominal bonds, and 49 bps for indexed-linked debt (ILD).[28] CEPA then proposes a 25 bps downward adjustment of the iBoxx index value in its low case, and assumes that outperformance would offset its estimate of 10bps transaction cost in the high case[29].

For real ILD, we do not consider that it is feasible to compare the real coupon with the nominal iBoxx benchmark, given the absence of a robust measure of inflation with which to deflate the nominal benchmark. Flaws in the measure of inflation will obscure any supposed halo.[30] The level of ILD debt issuance by energy networks is also relatively small compared to nominal issuance at around 25 per cent, and we expect will reduce over time under a switch to CPI. [31] For these reasons, we have focused our analysis on CEPA's approach to

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27 CEPA (February 2018) : Review of cost of capital ranges for Ofgem's RIIO, p.29-p.32.

28 For nominal bonds, CEPA compares the nominal coupons for bonds with at least 10 year tenor to the average A/BBB rated iBoxx non-financial corporates 10 year+ indices. For index-linked bonds, CEPA compares the real coupon with the "real" iBoxx indices deflated with 20-year breakeven inflation.

29 CEPA (February 2018) op, cit., p.36.

30 As we discuss in section 2.5.1, break-even inflation is an imperfect measure of expected inflation given the inflation risk premium.

31 Moody's (January 2016), Transition to CPI creates risks for water and energy networks, p.6.

estimating the supposed halo for nominal debt issuance which comprises three-quarters of debt issuance. We have identified two flaws that, if corrected, eliminate the supposed "halo effect":

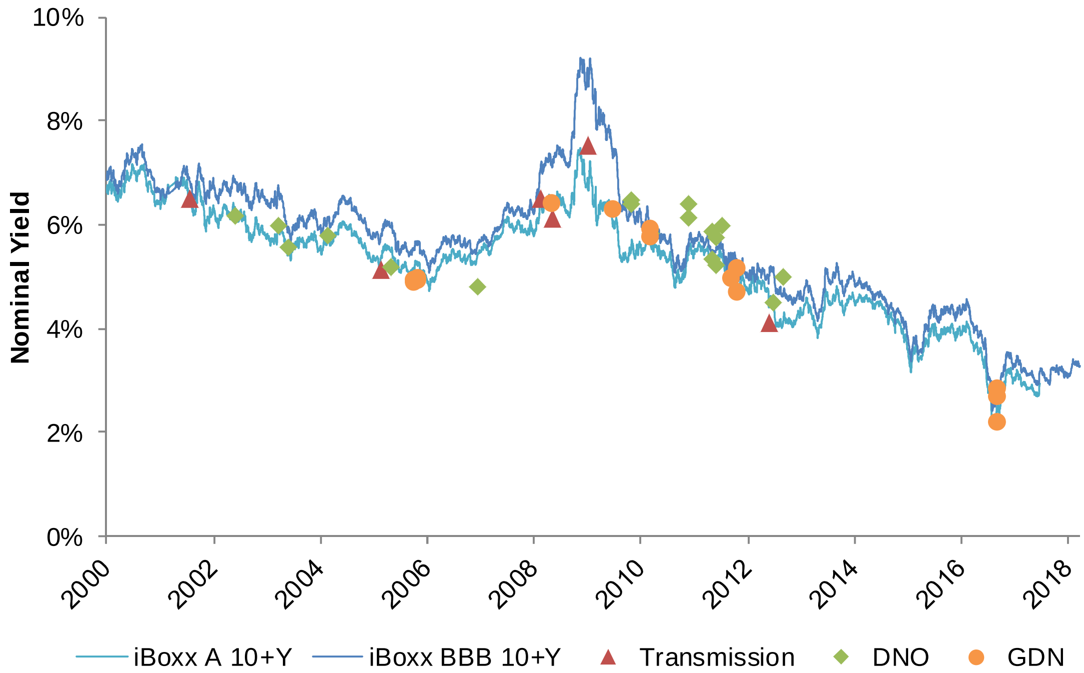
- **CEPA incorrectly uses coupon as its measure of the cost of debt:** CEPA's use of the coupon cost understates companies' cost of debt because many of the GBP bonds were issued below par. The appropriate measure of the cost of debt is the yield at issue, which accounts for non-par issuance, and was the approach used by Ofgem at RIIO-ED1 Strategy Decision, and the CMA at the appeal of Ofgem's RIIO-ED1 decision by British Gas Trading (BGT).
- **CEPA fails to correctly control for bonds' rating at issue:** CEPA fails to take into account that that energy networks' bonds were predominantly A rated *at issuance*, especially during the pre-2010 period where around 80 per cent of the energy networks' bonds were A rated.[32] Unsurprisingly, a comparison of predominantly A rated bonds at issuance to the average of A and BBB rated iBoxx indices will show "outperformance"; by contrast, comparing A rated bond issuance with the A rated iBoxx and BBB rated bonds with BBB rated iBoxx substantively reduces the halo.

Overall, we show that correcting for these two errors in CEPA's analysis reduces the so-called halo effect to practically zero.[33]

32 CEPA states that for nominal bonds "13% of shown coupons, or 25% by value, were issued at a rate higher than the average of the A and BBB values". However, using rating at issue, we have calculated that around two-thirds of bonds were issued at a rate higher than the average of the A and BBB values, materially higher than CEPA's estimates. One possible explanation for the difference is that CEPA has mistakenly used current rating instead of the rating at issue in its analysis.

33 We estimate an overall difference in energy network bonds' yield-at-issuance with the respective A or BBB rated iBoxx Corporate indices, ensuring a like-for-like comparison in ratings, of 3 bps.

Figure 2.4
Correcting for CEPA's errors on use of coupon and mis-match of rating, we show that there is no halo effect



Source: NERA analysis of data from Bloomberg and Markit iBoxx

2.4.4. In the absence of a halo, Ofgem should allow for an explicit debt issuance costs

At RIIO-1, Ofgem did not provide for companies debt transaction costs at it considered that these could be remunerated by company outperformance of the index (the so-called halo). Given that there is no evidence of a halo effect for energy networks, Ofgem should provide an explicit allowance for debt transaction costs. Regulators have typically included an allowance in the cost of debt for the unavoidable transaction costs associated with issuing and subsequently holding debt. These include:

- **Issuance costs**, i.e. the upfront fees that must be paid to financial intermediaries when new debt is issued (such as underwriting fees, advisory fees, arrangement fees, legal fees, rating agency issue fees) as well as any ongoing costs for maintaining a debt portfolio (e.g. ongoing rating agency fees); and
- **Cost of carry** which may include:
  - the cost of holding any necessary liquidity/working capital facilities; and
  - the cost associated with holding more of any debt finance raised as additional cash reserves.

At RIIO-1,Ofgem estimated the transaction costs at 20 bps which, in the absence of the halo, should be provided for in full.

2.5. Option A: Options for inflation

Ofgem also intends to consider its calculation of the inflation rate to derive the real cost of debt allowance from observed nominal values. Ofgem cites the potential use of a 20 year break-even rate to match the average tenor of issuance of networks' debt which we address below.[34]

Ofgem has also raised the prospect that it may adopt CPI indexation of the RAV at RIIO-2.[35] The adoption of CPI indexation would necessitate a change from its current approach to deflating the nominal iBoxx index to derive a real cost of debt allowance. In this case, we have identified three potential options: continued use of break-even inflation plus a RPI-CPI wedge; the use of an ex post inflation assumption (as per Ofwat's proposals); or, outturn inflation as applied to the RAV.

2.5.1. Break-even inflation does not allow for cost-recovery

Ofgem currently deflates the nominal benchmark by break-even inflation, as derived from 10 year gilts as determined for the same time period as the determination of the nominal benchmark.

Break-even inflation overstates expected inflation which means that energy networks are unlikely to recover their actual nominal debt costs. Breakeven inflation overstates inflation because of the "inflation risk premium" in the nominal gilt yield. [36] In theory, the spread between the nominal gilt yield and index-linked gilt yield includes both the expected inflation for the remaining life of the nominal gilt as well as the inflation risk premium, which compensates the investors for the risk of *unexpected* changes in inflation.[37,38] For example, in its PR14 Final Determination, Ofwat subtracted an inflation risk premium of 0.3 percentage points from breakeven inflation data when considering breakeven inflation as a cross-check on its "long-run" inflation estimate of 2.8%. [39]

2.5.1.1. 20 year break-even inflation is even more problematic

The use of a 20-year breakeven inflation is even more problematic, given the well documented distortions in the index-linked gilt market for long maturities. A large portion of

[34] Ofgem (March 2018) op. cit., p.80

[35] Ofgem (July 2017) Open letter on the RIIO-2 Framework, p.10. Link: https://www.ofgem.gov.uk/publications-and-updates/open-letter-riio-2-framework

[36] See Bekaert, G., and Wang, X. (2010). Inflation risk and the inflation risk premium. Economic Policy, 25(64), 755-806. Campbell, J., & Viceira, L. (2009). Understanding inflation-indexed bond markets (No. orrc09-20). National Bureau of Economic Research.

[37] See Shen (2006), Liquidity Risk Premia and Breakeven Inflation Rates, Federal Reserve Bank of Kansas City, Economic Review, Second Quarter 2006.

[38] This is also recognised by the Bank of England, which notes that care is required in interpreting the market data as a measure of inflation expectations because "*Illiquidity in the conventional and index-linked gilt markets could distort this measure, and in practice there will be an 'inflation risk premium' incorporated in the implied inflation rate.*" See Bank of England "Notes on the Bank of England UK Yield Curves", page 5, footnote 8.

[39] See Ofwat, December 2014, *"Setting price controls for 2015-20. Final price control determination notice: policy chapter A7 – risk and reward"* – page 36 and footnote 6.

the long-dated ILD gilt is held by UK pension funds for asset-liability management, but the pension funds do not actively trade their bonds, because the liability matching portfolios are in generally rebalanced passively. Therefore, the majority of the long-dated ILD gilt market is infrequently traded and lacks liquidity. [40]

The potential for 20 year breakeven inflation to overstate inflation is apparent when considering alternative evidence from the OBR and HMT, commonly used by UK regulators including the CMA as a basis of forecasting inflation[41]. These measures support long-term forecast of 3 to 3.1 per cent (see Table 2.1 below), whereas the current 20Y break-even supports a value of 3.4 per cent.

Table 2.1
Forecasts from HMT and OBR support RPI inflation of 3 to 3.1 per cent below 20Y BE of 3.4 per cent

	2018	2019	2020	2021	2022
HMT (Feb 2018)	3.5	3.0	3.0	3.1	3.1
OBR (Mar 2018)	3.7	3.0	2.9	2.9	3.0

Source: HM Treasury (February 2018), Forecasts for the UK economy: a comparison of independent forecasts, p.16; and Office for Budget Responsibility (March 2018), Economic and fiscal outlook, p.83.

2.5.1.2. There is no market based CPI measure

The adoption of CPI indexation would complicate the use of break-even inflation given the absence of an equivalent market based CPI measure, i.e. there are no CPI nominal and ILD gilts to construct a CPI break-even.

Therefore, if Ofgem were to change to CPI indexation, Ofgem would need to adjust the RPI break-even measure for an assumption on the RPI-CPI wedge, e.g. drawing on independent forecasts of the expected wedge.[42]

2.5.2. Fixed ex-ante inflation assumption accentuates risk

An alternative to break-even is to use an ex ante forecast. At GD17, the Utility Regulator in Northern Ireland determined that it would deflate the actual outturn nominal iBoxx cost at the time of refinancing using its estimate of ex ante inflation set at the price control.[43]

Nominal debt costs and inflation co-vary, i.e. a movement in inflation will result in a movement in nominal debt costs.[44] As a result, it is incorrect to treat these two elements as

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40 See discussion e.g. in Competition Commission (March 2014), Northern Ireland Electricity Limited price determination, p.13-21.

41 CMA (October 2015), Bristol Water plc, p.313

42 For a description of independent estimates, see: NERA (2016) Use of inflation indices in water sector, p.8. Link: http://www.nera.com/content/dam/nera/publications/2016/160126_report_NERA_indexation_FINAL%20(3).pdf

43 Utility Regulator (2017) GD17 Final Determinations, Annex 14 – Rate of Return Adjustment Mechanism; Annex 15 – Rate of Return Adjustment Model. Link: https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/2016-09-15_GD17_Final_Determination_-_final_0.pdf

independent, i.e. we should not set forecast debt costs based on the nominal iBoxx for RIIO-2, in combination with an ex ante inflation assumption.

Based on the empirical data, the use of an ex ante inflation assumption is likely to accentuate risk. For example, an increase in inflation is likely to lead to an increase in the nominal debt cost – leaving *real* debt costs unchanged. However, if the allowance is set based on the outturn nominal iBoxx benchmark, and yet a fixed ex ante inflation, the real allowance will increase and companies will over-recover. Likewise, a step-down in inflation during the review period may lead to under-recovery.

2.5.3. Outturn inflation may provide the best measure

A third approach is to derive real cost of debt allowance based on the inflation measure used to index energy networks' RAVs. .

There is a potential downside from using outturn inflation: in any one year outturn inflation may differ substantively from the implied inflation in nominal debt costs, which will reflect inflation expectations over the period of the debt, and therefore the real cost of debt allowance recovered in any year through allowed revenues may be low (or indeed high). The resulting volatility in the allowed real cost of debt component of revenues could potentially be avoided by using an average inflation measure, e.g. using an average inflation measure calculated over a number of years.

On balance, this is our preferred approach as it ensures that investors recover their nominal cost of debt: the inflation element of the cost of debt is recovered as a capital gain on the RAV, and the remaining real element is recovered as a return on the RAV.

2.6. Option B is less likely to meet Ofgem's objectives than a well-designed option A

Ofgem also consults on whether to adopt a fixed allowance for existing debt plus indexation for new debt only, along the lines of Ofwat's intended approach for PR19. For PR19, Ofwat has proposed to set the embedded cost of debt based on the industry median cost, and allow for the new cost of debt based on the iBoxx index.[45]

If Ofgem were to adopt such an approach, we consider that any calculation of the industry embedded cost of debt should exclude Cadent, given its atypical debt profile and cost following the recent sale.

However, we consider that Ofgem's option B is less likely to meet Ofgem's objectives than a re-calibrated GD1 mechanism (Ofgem's option A), assuming option A is designed well.

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44 The correlation co-efficient is around 0.5 for both nominal Libor to RPI, and nominal Libor to CPI

45 Specifically, Ofwat proposes to use the company-level median cost of debt to avoid the impact of outliers. See: Ofwat (December 2017) op. cit, Link: https://064f1d25f5a6fb0868ac-0df48efcb31bcf2ed0366d316cab9ab8.ssl.cf3.rackcdn.com/wp-content/uploads/2017/12/Appendix-12-Risk-and-return-CLEAN-12.12.2017-002.pdf

There is greater merit to setting embedded debt costs based on a trailing average iBoxx value rather than the embedded cost of debt for the following reasons:

- **iBoxx provides an objective measure of the cost of debt**. By contrast, calculation of the industry average requires subjective decisions and therefore regulatory risk. For example, Ofwat excludes certain types of bonds from its calculation of industry embedded debt costs, e.g. those issued pre-2000; callable; non-GBP; as well as derivatives.[46] At PR19, Ofwat calculated a range for actual embedded debt cost of 1.3 per cent to 1.9 per cent (real, RPI) drawing on different averaging techniques, and has proposed an allowance of 1.59 per cent (real, RPI).[47]
- **Calculation of industry average involves greater regulatory cost:** The use of industry own costs also increases regulatory costs for the regulator, and the regulated entities; in part, because of the subjective nature of the calculation of embedded debt costs.
- **The Ofwat approach may not work well for TOs:** In the case of TOs, where the industry comprises only three companies, with NG the dominant company by regulated value, the individual companies (or at least NG) own debt costs may have a material impact on the industry embedded cost allowance. At PR19 framework decision, Ofwat considered that the use of company own debt costs blunts incentives. The CMA has also supported an industry average approach (at BW 2015 appeal), as opposed to using companies' own debt costs. [48]

However, the relative merits of the options depend crucially on whether option A is well-calibrated to allow for recovery of debt costs. If not, option B may be preferable based on Ofgem's criteria.

2.7. Option C: Passing through debt costs may increase complexity and reduce incentives

The pass-through of debt costs is a common feature in other jurisdictions, e.g. the US. However, as with option B, we consider that this option is potentially inferior to a well-designed and re-calibrated GD1 mechanism.

First, the use of the industry embedded debt cost could raise concerns where energy networks' gearing varies materially from Ofgem's notional gearing assumption, leading to an inconsistency in the actual and notional rating and debt cost. Second, the use of company's own embedded debt cost and gearing could diminish incentives to issue debt efficiently. Third, the approach imposes a greater regulatory burden on the regulator and the company.[49]

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46 Ofwat (December 2017) op. cit., Appendix 12 – Aligning risk and return, p. 77. Link: https://www.ofwat.gov.uk/wp-content/uploads/2017/12/Appendix-12-Risk-and-return-CLEAN-12.12.2017-002.pdf

47 Ofwat (December 2017) op. cit., Appendix 12 – Aligning risk and return, p. 77. Link: https://www.ofwat.gov.uk/wp-content/uploads/2017/12/Appendix-12-Risk-and-return-CLEAN-12.12.2017-002.pdf

48 CMA (2015) Bristol Water price determination, p.305, para 10.54

49 See for example, CMA (2015) Bristol Water appeal, Appendix 10.1, Cost of Capital

Ofwat has recently considered the use of company's actual debt and gearing as opposed to notional, and confirmed its established notional approach to setting embedded cost of debt allowances. Specifically, Ofwat cited three reasons to support a notional approach. These were:[50]

- *"Customers should not be responsible for funding inefficient financing structures of debt costs"*
- *"Companies are free to choose their actual capital structure and the debt instruments raised, but customers will only face the efficient cost of debt for a notionally structured company."*
- *"Using a notional approach rather than basing the cost of debt allowance on actual costs provides incentives for companies to outperform.*"

The CMA has also supported both Ofwat and Ofgem's approach to using notional capital structures and industry average debt costs in their respective price controls, but itself has drawn on Bristol Water's own debt costs given that "*it was in a position to conduct a more detailed examination of the company in question*".[51] In its final decision for Bristol Water, the CMA used a combination of both actual company and industry debt costs.

2.8. Conclusions on the cost of debt mechanism

We consider that a re-calibrated GD1 mechanism is most likely to meet Ofgem's objectives, assuming that the index is well designed. The key design elements comprise:

- **Conceptually correct trailing average is 20 years:** Our analysis shows that neither the current GD1 nor the ED1 cost of debt mechanisms allows SGN or the industry, excluding Cadent, to recover debt costs over GD2 under our interest rate scenarios. The conceptually correct trailing average is 20 years, in line with the efficient tenor at issuance. However, a starting trailing average of 15 years, such that the first year of the trailing coincides with DN sales in 2005 and therefore accurately captures the industry historical debt issuance, may be reasonable in this context.

  Cadent's debt costs should be excluded from the analysis to inform the re-design of the GD1 mechanism given its atypical profile and costs.

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50 Ofwat (September 2016), Water 2020: consultation on the approach to the cost of debt, p. 16

51 CMA states the following:
"*In addition, we support Ofwat's use of a notional cost of embedded debt in the context of a multi-company framework. As well as being consistent with other regulators (e.g. Ofgem), this has the benefits of allocating risk/reward to the people best able to manage it (i.e. management), incentivising efficient methods and timings of raising debt, and removing incentives to obfuscate actual debt costs through complex arrangements and capital structures.*
In the context of our determination, we did not seek to undermine this approach, but were in a position to conduct a more detailed examination of the company in question. We therefore considered that it was appropriate for us to consider both the notional level, consistent with the approach that Ofwat used and also the specific actual costs incurred by Bristol Water". Source: CMA (2015) Bristol Water price determination, p. 304. Link: https://assets.publishing.service.gov.uk/media/56279924ed915d194b000001/Bristol_Water_plc_final_determination.pdf

- **Allowance for transaction costs:** CEPA's analysis of companies' debt costs relative to the iBoxx index fails to examine yield-at-issuance and control for the higher rating of energy market bonds at issuance relative to the average A and BBB iBoxx indices. Correcting for these factors, we show that the halo-effect is practically zero and Ofgem should set an explicit allowance for transaction costs, as, acknowledged by the CMA at BGT appeal.
- **Break-even inflation may not allow for cost-recovery:** We have set out options for the derivation of a real cost of debt from the nominally observed iBoxx benchmark under a switch to CPI indexation. The options are to use the current break-even approach plus an estimate of the CPI-RPI wedge; an ex-ante inflation assumption (as per Ofwat's proposed approach and UR in NI); or, the outturn inflation rate applied to RAV. Break-even inflation is likely to overstate inflation and understate real debt costs; the use of 20 year break-even is particularly problematic given the illiquidity of long-dated IL gilts.

  Our preferred approach is to use the outturn inflation rate as this largely mitigates risk for investors in recovering nominal debt costs.

We consider that both options B and C are less likely to meet Ofgem's objectives than a re-calibrated option A, assuming option A is well-designed. Both options B and C are likely to be more costly and intrusive as they require an investigation of companies' actual costs, and may blunt incentives to minimise debt costs (notably in relation to option C). However, the relative merits of these options depend crucially on design of the re-calibrated GD1 mechanism.

3. Cost of Equity Indexation

Ofgem has proposed a cost of equity indexation approach for RIIO-2 where the cost of equity is updated annually to reflect market movements.[52] In considering cost of equity indexation, CEPA, Ofgem's consultant, has identified three broad options:[53]

- Index risk-free rate only
- Index risk-free rate (RfR) with offsetting adjustment for the ERP
- Index the TMR (and RFR)

As noted by CEPA, the preferred option will depend on the view of the regulator on the relationship between the risk-free rate and ERP.[54] As Ofgem, along with other GB regulators, determines the cost of equity based on a so-called TMR approach, we consider that the only viable option is to index the TMR and RFR, i.e. the third option.

Ofgem also focusses on the third option in its consultation document where it proposes "by way of example" a change to the equity allowance set at review based on the change in the RfR multiplied by a (1-beta) factor plus the TMR multiplied by beta, but where the TMR and beta are held constant during the price control review. That is, Ofgem's proposal falls back to RFR*(1-beta)[55]

CEPA do not recommend indexation of the beta element given that it "*should not move materially within any price control period*"[56], and Ofgem proposes to set a constant beta in its example of how indexation may work.[57] We agree with CEPA that it is not desirable to index the beta over the price control given the volatility of beta estimates and the difficulty of explaining short-term changes in terms of changes in systematic risk.

In this chapter, we describe how option 3 could work in practice. We conclude that Ofgem has not made the case for indexation. The case for cost of equity indexation should rest on an analysis of standard regulatory criteria for assessing whether costs should be passed-through, including whether costs are volatile such that the regulator cannot set a reasonable ex ante allowance, and the ability to objectively measure changes in the cost of equity. We show that the cost of equity is broadly constant over time, and therefore it is reasonable to set an ex ante allowance. In addition, we note that long-run historical TMR data may provide an objective measure of the cost of equity, but the specific index and its interpretation (e.g. in terms of averaging techniques) will need to be clearly specified in advance.

52 Ofgem (March 2018) RIIO-2 Framework Consultation, p. 92

53 CEPA (February 2018) Review of Cost of Capital Ranges for Ofgem's RIIO-2 for Onshore Networks, p.58

54 CEPA (February 2018) op. cit., p.58

55 Ofgem (March 2018) RIIO-2 Framework Consultation, para. 7.64, p. 93

56 CEPA (February 2018) op. cit., p.57

57 Ofgem (March 2018) RIIO-2 Framework Consultation, para. 7.64, p. 93

3.1. If applied, indexation should be based on indexing RFR and TMR (CEPA's option 3)

Unlike cost of debt indexation which can be based on observed corporate debt indices, there is no comparable index for the cost of equity which instead has to be estimated using a financial model. Ofgem and other UK regulators have historically relied on the capital asset pricing model (CAPM) to estimate the cost of equity. The familiar CAPM can be written as:

1. $Ri = RfR + \beta i*ERP$,

Where Ri is the expected return on equity; βi is the equity beta which measures the systematic risk of the equity of the regulated firm; RfR is the risk free rate; and ERP is the equity risk premium which is equal to the TMR minus the RfR.

Equation 1 can therefore be re-stated as:

2. $Ri = (1-\beta i)*RfR + \beta i*TMR$

As can be seen from equation 2, in the CAPM, the expected return on equity can be expressed as a weighted average of the RfR and the TMR with the weights depending on the equity beta. Where the equity beta is close to 1, or the average for the market, (as is the case for energy networks at RIIO-1),[58] the weight on the RfR is low and the far greater the weight rests on the TMR. As a consequence, Mason, Miles and Wright, academics that advised GB regulators at previous reviews, noted that the focus of GB regulators should be on estimating the TMR given its dominance in the determination of the cost of equity for regulated networks. They also noted that this is fortunate, as there is far greater certainty over the value of the TMR, and far less certainty about the true historical risk free rate and by implication the ERP, which have demonstrated far greater volatility over time.[59] The authors have confirmed their support for a TMR approach in the most recent report for the UK regulators' network (UKRN).

Most GB regulators, as well as the Competition and Markets Authority (CMA), have focussed on the estimation of the TMR in determining the allowed return on equity, as opposed to estimating the ERP directly. The CMA explained that its reason for adopting such an approach is that it provides more stable estimates:[60]

> "*Our preferred approach is to deduct our estimate of the RFR from our estimate of the equity market return [TMR] to derive the ERP. […] the market return has tended to be*

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58 The implied allowed equity beta for energy networks at the RIIO-1 controls was between 0.9 and 0.95. Source Ofgem (December 2012), RIIO-GD1: Final Proposals – Finance and uncertainty supporting document, p.22, Link: https://www.ofgem.gov.uk/ofgem-publications/48156/3riiogd1fpfinanceanduncertainty.pdf; Ofgem (December 2012), RIIO-T1: Final Proposals for National Grid Electricity Transmission and National grid Gas – Finance Supporting document, p.24, Link: https://www.ofgem.gov.uk/ofgem-publications/53602/4riiot1fpfinancedec12.pdf

59 Mason, Miles and Wright (2003), A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K., p.4. Link: https://www.ofgem.gov.uk/ofgem-publications/50794/2198-jointregscoc.pdf

60 CMA (March 2014), NIE Limited price determination, p. 13-16, para. 13.82. Link: https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

less volatile than the ERP […], and there is some evidence of the ERP being negatively correlated with Treasury bill rates over the short term."

Ofgem also adopted a TMR approach to determining the cost of equity at RIIO-1 and previous reviews, and has confirmed its support for a TMR approach at RIIO-2.

Given the general support for a TMR approach, CEPA's first two proposed methods for indexation, risk-free rate only and risk-free rate plus ERP, are not viable because they do not start from the premise that it is the TMR that needs to be estimated directly given the relative stability of the TMR, which has been accepted by GB regulators. For example, CEPA's option 1 assumes a constant ERP, and a varying RFR, implying that the TMR is not stable over time which contradicts GB regulators assumption that it is (the premise of the TMR approach). CEPA's second option required arbitrary assumptions around the co-variance between the RFR and ERP, which again implies a non-constant TMR.

Ofgem itself appears to acknowledge that only option 3 is viable as its example is based on this option.

3.2. Ofgem's own example suggests that there is no requirement for indexation

Ofgem proposes to hold the TMR constant over the period of the price control in its example of how equity indexation may work. [61] That is, Ofgem proposes a TMR approach as the basis for indexation, as per equation 2 above:

(2') $Ri = (1-\beta i)*RfR + \beta i*TMR$

Ofgem then notes that if it were to assume that the TMR and beta were constant over the course of a price control, then the second term falls away, and the indexation becomes (1-beta)*RfR.[62]

If implemented, we agree that it is reasonable to hold the TMR constant over the review period. The only reasonable alternative is to draw on a long-run historical series as per the DMS, which will not change materially over the course of any review, as we explain below.

However, our analysis (and Ofgem's own proposal) suggests that there is not a strong case for indexation. As with other uncertainty mechanisms, indexation should be used where costs are uncertain such that it is difficult to set a reasonable ex ante allowance, e.g. as with the cost of debt. Given the constancy of the TMR over time, and the fact the term (1-beta)*RFR approximates to zero, there is a strong case for setting an ex-ante allowed return on equity, as per previous controls and all other GB regulators. By contrast, an indexation mechanism would complicate the price control process unnecessarily and contradicts Ofgem's intention to simplify price control arrangements.

[61] Ofgem (March 2018) RIIO-2 Framework Consultation, para. 7.64, p. 93

[62] Ofgem (March 2018) RIIO-2 Framework Consultation, para. 7.64, p. 93

3.3. Identifying an objective index: long run historical TMR

Under a TMR equity indexation mechanism, there are two potential approaches to updating the TMR during the course of the review period. One approach to indexing the TMR is to draw on *realised* historical returns. This approach assumes that historical realised returns provide an unbiased estimate of the *expected* return over long time periods, given that the impact of errors should cancel out over long time frames in expectation. This is the approach to setting the TMR recommended by UK regulators' advisers.[63]

The alternative approach is to draw on current or forward looking data, such as the dividend growth model (DGM). However, the DGM estimates tend to be subjective and sensitive to input assumptions, notably around dividend price growth. At recent price controls, Ofgem as well as other regulators (including the CMA) have tended to focus on long run historical estimates to determine the cost of equity allowance, with the DGM employed as a cross-check on the results derived from long run averages.[64]

3.3.1. The weight of evidence supports the use of long-run TMR measure

The argument for adopting a long run index measure depends on whether the expected TMR is broadly constant over time, and thus whether historical returns provide an unbiased measure of the expected future return.

Given the marked historical volatility in the RfR (see for example, see Figure 3.1), the constancy of the TMR depends on whether these observed variations in the RfR are broadly off-set by changes in the ERP, that is, whether ERP and RfR negatively co-vary over time. In general, the financial literature supports the negative co-variance of the RfR and ERP over time, and therefore the time constancy of the TMR.[65]

As an example, Siegel (1998) analysed 200 years of US stock market data, and concluded that the TMR shows a remarkable degree of stability over time, in contrast to other asset classes such as the risk-free rate.[66]

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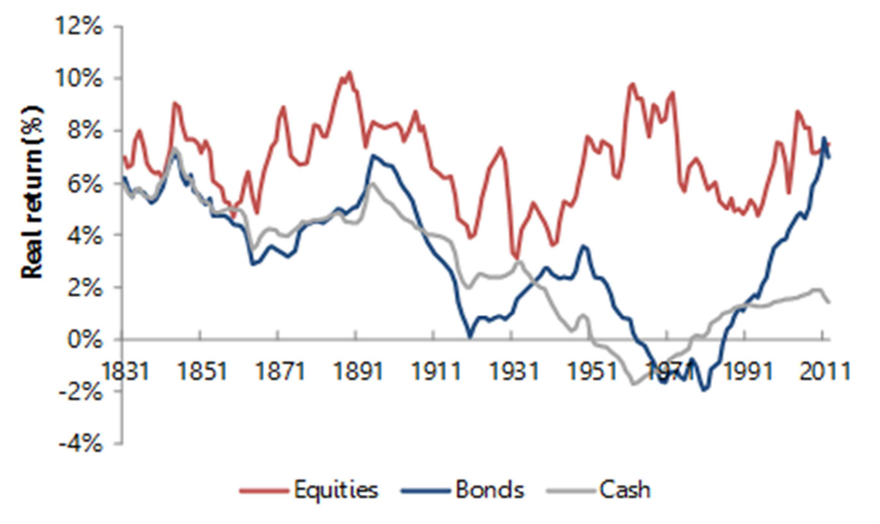
63 Wright, Stephen. Et al (2018) Estimating the cost of capital for implementation of price control by UK regulators, a report commissioned by UKRN, p. 8. The authors state: "*We recommend that regulators should continue to base their estimate of the EMR [TMR] on long run historical averages [..].*"

64 See e.g. Ofwat (January 2014), op.cit., section A1.4, Ofgem or CMA (March 2014), op.cit., para 13.137.

65 See for example: NERA (2017) The total market return for determining the cost of equity at RIIO-2. Link: http://www.nera.com/content/dam/nera/publications/2017/171103_TMR_report_NERA.PDF

66 Siegel (1998), Stocks for the Long Run. McGraw-Hill, second edition, p.11, 13.

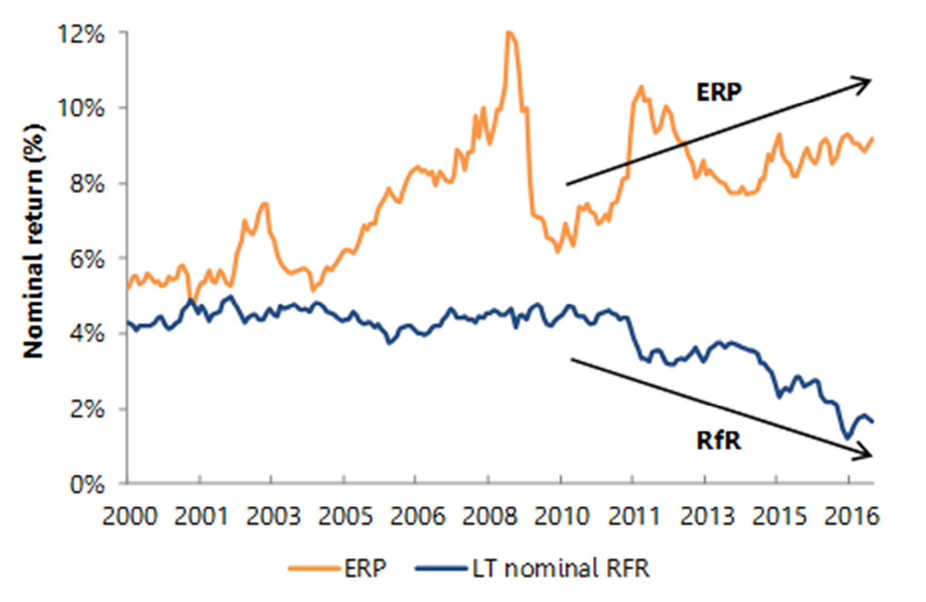
Figure 3.1
US TMR shows "a remarkable degree of stability" over time which supports use of historical TMR as index for cost of equity



Source: Siegel (1998) for the period 1801 to 1899 then updated by DMS. See: Wright and Smithers (2014), The cost of equity capital for regulated companies: a review for Ofgem

In addition, prominent economic institutions, such as the Bank of England, have recognised that the recent low interest rates and economic uncertainty have led to increased ERPs.[14] Indeed, the Bank of England's own estimates of the ERP, as derived from its DGM model, have increased markedly with the recent fall in interest rates (see Figure 3.2). Again, the inverse relationship between the ERP and RFR supports the notion of a constant TMR, and the use of a long-run historical measure as the basis for a TMR index for RIIO-2.

Figure 3.2
Bank of England DDM supports theory that reduction in RFR offset by increases in ERP over recent period



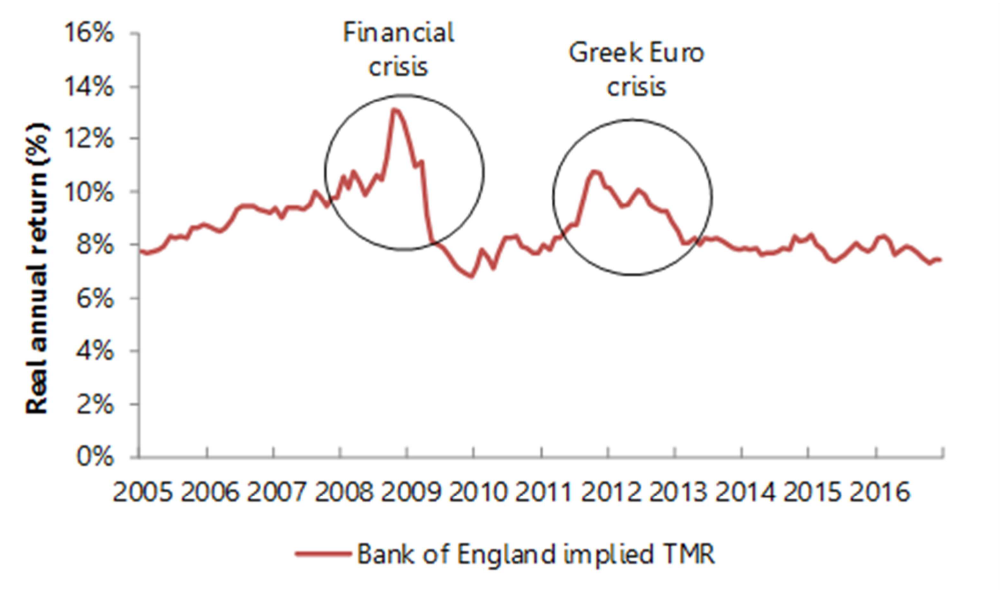
Source: NERA calculations based on Bank of England data

3.3.2. An alternative to a historical TMR index would be forward-looking DGM based index

An alternative to using an historical TMR measure as the basis for a cost of equity index would be to draw on forward-looking DGM measures. At previous reviews, the CMA has drawn on TMR estimates from the Bank of England's DGM. Recent evidence from the Bank of England supports a TMR of between 7 and 8 per cent, although much higher values were observed during the financial and Greek crises, as shown in Figure 3.3.

However, the DGM approach is sensitive to assumptions around future dividend policy, a key and unobserved determinant of the DGM. For example, PwC's recent DDM estimates of the TMR lie in the range 5.4 to 5.8 per cent in real terms,[67] although we consider these estimates are downwardly biased due to errors that PwC makes in its assumptions on short term and long term dividend growth.[68]

Figure 3.3
DGM TMR estimates from Bank of England support a "current" TMR of around 7 to 8 per cent (% real RPI returns): But estimates can be volatile over time and subjective



Source: NERA calculations based on Bank of England data

[67] PwC derives a nominal TMR range of 8.3 to 8.8 per cent, equivalent to 5.4 to 5.8 per cent real, assuming 2.8 per cent RPI inflation in line with PwC. Source: PwC (June 2017), op.cit., p.82, 87.

[68] See NERA (November 2017) op. cit., pp 8-9. Link: http://www.nera.com/content/dam/nera/publications/2017/171103_TMR_report_NERA.PDF

3.3.3. DMS provides a suitable basis for long-run TMR index

As explained above, given the stability of the TMR over time, and the subjectivity of DDM/DGM based TMR estimates, the only reasonable approach for cost of equity indexation is to draw on a TMR index based on long run historical values.

As the basis for the TMR index, we recommend use of long-run historical averages published by DMS, and drawn on by CMA and Ofgem to determine the TMR at previous reviews. Table 3.1 shows an update of the CMA calculations in its determination for Northern Ireland Electricity using data over the period 1900-2016 from the latest DMS 2017 publication.

Table 3.1
The CMA has drawn on long-run DMS to inform TMR, citing a range of averaging techniques and holding periods. These methods could form the basis for a TMR index

	Simple	Overlapping	Blume	JKM
1Y holding	7.1	7.1	7.1	7.1
2Y holding	7.5	7.0	7.1	7.1
5Y holding	7.2	6.8	7.0	6.9
10Y holding	6.7	6.7	6.9	6.7
20Y holding	7.7	6.8	6.8	6.2

Source: NERA calculations using DMS (February 2017),Credit Suisse Global Investment Returns Yearbook 2017[69]*, CMA (2014), Northern Ireland Electricity price determination, Final Determination, p. 13-27, Table 13.7.*
Note: The figures in black in the table represent different historical estimates considered by the CMA for NIE (2014), calculated using updated DMS data up to 2016.[70] *The figures circled in green represent the difference between the updated estimates and the estimates presented by the CMA in NIE (2014).*

As shown in Table 3.1 , the historical TMR estimates lie in a range between 6.2 and 7.7 per cent, depending on the averaging technique and holding period.

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[69] We note that the 2017 DMS publication includes real returns for the UK market since 1988 which have been calculated using CPI as opposed to RPI inflation. (See DMS (February 2017), Credit Suisse Global Investment Returns Yearbook 2017, p.212.) To ensure consistent treatment of inflation, we have re-calculated the real UK historical returns from DMS for 1988 onwards on an RPI deflated basis.

[70] The simple approach calculates the arithmetic mean for successive time periods (and therefore there are few observations for long holding periods) and the overlapping approach is identical other than it allows for overlapping time periods. For holding periods greater than 1 year, the simple approach first calculates the compounded nth period return (e.g. for a 5-year holding period, it calculates the 5-year compound return earned in the consecutive periods 1-5, 6-10, 10-15 etc.), and then takes an average of these 5-period compound returns. The overlapping approach is identical other than it allows that the compound 5-year return is calculated for periods 1-5, 2-6 etc. The Blume adjustment takes a weighted average of the arithmetic and geometric returns, and the JKM is a statistical approach that provides efficient estimates for small samples, but this adjustment also effectively produces unbiased estimates of the nth period return as a weighted average of the geometric and arithmetic averages over the observation period.

Table 3.1 shows that the averaging technique and assumed holding period is an important factor in estimating the TMR. We consider evidence supports the use of relatively short holding periods.[71,72]

Overall, we do not recommend that the TMR index draws on the simple average estimates based on long holding periods, as these estimates are based on a small number of observations. We also do not recommend the use of very long holding periods of 10-20 years which are not supported by empirical evidence on investor behaviour. The highlighted cells reflect potential approaches for determining the TMR index drawing on DMS data.

3.3.4. RFR could be based on spot market evidence, or long run averages

Under the TMR approach to indexation, we would also need to index the RFR (as per equation 2 above). There are two broad approaches used by UK regulators to determining the RfR which could be used as the basis of a cost of equity index:

- long-run historical averages or
- short-run market evidence, such as spot gilt rates.

Evidence from short-run gilt rates suggests a negative real yield of between 1.5 and 2 per cent for a 10 year gilt (see Figure 3.4 below). The Figure also shows that the real yield is expected to increase to around zero per cent over RIIO-2 period.

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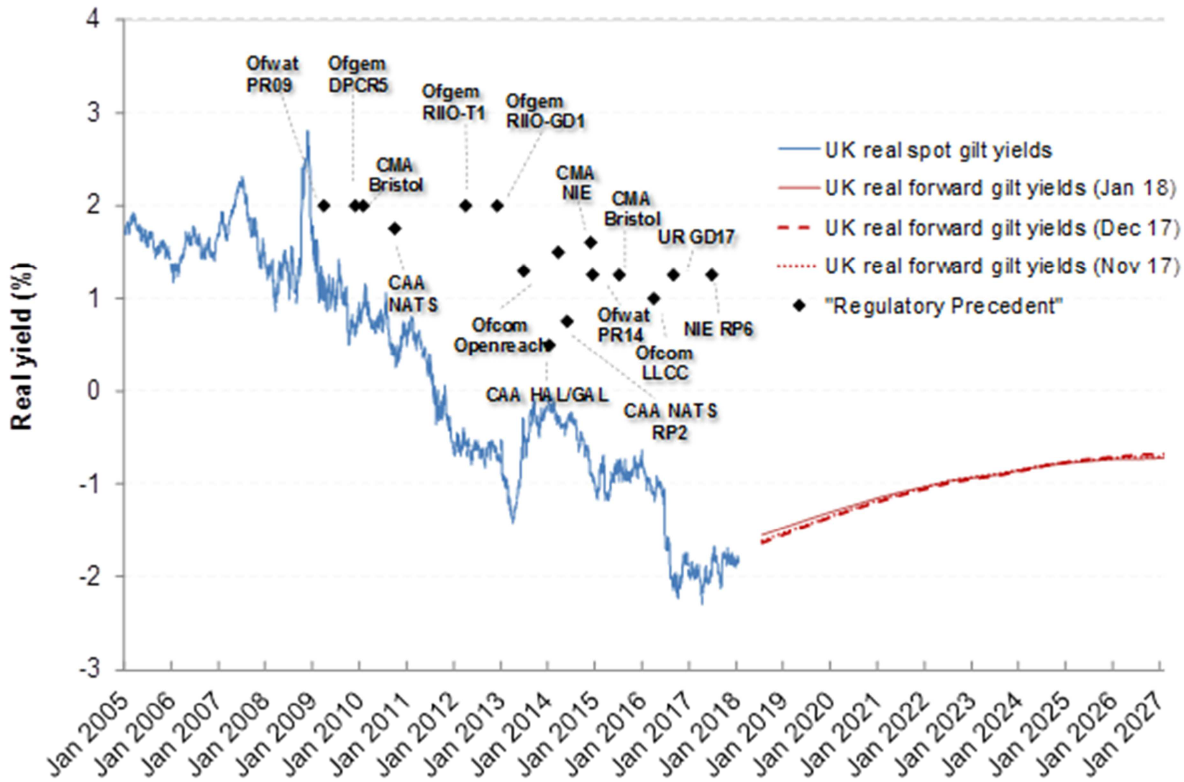
71 GB regulators such as Ofgem and Ofwat have typically considered the TMR for a holding period of 1 year. The use of short-term holding periods is consistent with evidence from a survey of equity market participants by the CFA Institute UK that suggests that the average holding period is between 1-2 years. Source: Kay Review of UK Equity Markets and Long-Term Decision Making, Interim Report, Feb 2012I; CFA UK response to the Kay Review of UK Equity Markets and Long-Term Decision Making – Call for Evidence

72 Helm and Tindall (2009) find that most utilities are held by private equity or infrastructure funds, where the former have an average holding period of 4-5 years while the latter tend to be more long-term. Helm and Tindall (November 2009), The evolution of infrastructure and utility ownership and implications, *Oxford Review of Economic Policy*, Vol 25, pp 411 – 434

Figure 3.4
Spot and forward evidence supports a RfR below zero per cent (real)



Source: NERA analysis of Bloomberg and Bank of England data

As can be seen from Figure 3.4, at recent reviews, UK regulators generally placed greater weight on long-run evidence on the RfR, with determinations in the range of 0.75 to 2 per cent real, reflecting long-run averages with some downward adjustment to reflect the lower spot and forward yield evidence. However, in its recent consultation framework, CEPA draws on mainly short-run evidence, proposing a RfR in the range of -1.75 per cent to -0.60 per cent, based on spot and forward 10 year gilts.[73]

In theory, an indexation approach could draw on either a short-run or long-run measure of the RFR. The long-run measure could reasonably be based on the same period as the TMR, e.g. over the full DMS database which provides more than 100 years of data, although would not reflect changes in credit markets and the index will change only slowly over time. The short-run index measure could be based on 10Y gilts rates.

3.4. Conclusions on cost of equity indexation

We do not consider that there is a strong case for cost of equity indexation. As we describe above, we do not agree that the cost of equity varies over time such that Ofgem is unable to set a reasonable allowance for the price control period. In addition, although long-run

73 CEPA (February 2018) Review of Cost of Capital Ranges for Ofgem's RIIO-2 for Onshore Networks, p. 46.

historical TMR data may provide an objective measure of the cost of equity, the specific index, time period, and averaging techniques will need to be clearly specified in advance.

However, if implemented, we consider that any indexation of the cost of equity should have the following features:

- Index the TMR directly, as opposed to separately indexing the ERP and RFR. All UK economic regulators focus on TMR estimation in determining the cost of equity at review. This corresponds to CEPA's option 3.
- Draw on a long run historical values for an established database of TMR, e.g. DMS database, as opposed to forward-looking estimates, e.g. based on DGM, which are more subjective.

The RFR could draw on either long-run historical values which provide for greater stability in the cost of equity estimate. The alternative is to use current market data, such as gilt yields, as proposed by CEPA in setting the RFR for RIIO-2.

We do not propose that the beta is indexed, in line with Ofgem's proposal.

Our proposed approach is broadly in line with Ofgem's indexation example, where it suggests that the index is based on the RfR multiplied by (1-beta), and the TMR multiplied by beta (as per equation 2 above).

4. Ensuring Financeability

In its Framework Consultation, Ofgem states that it has a duty to have regard to companies' ability to finance their activities. Ofgem states that at previous reviews it has assessed whether companies can maintain an investment grade credit rating drawing on rating agencies' methodologies, and confirms that it intends to undertake a similar approach at RIIO-2.[74]

However, it also notes that its proposed cost of equity and a declining cost of debt allowance are likely to lead to a lower overall baseline return at RIIO-2 which will make it more challenging to meet the standard financeability metrics. Ofgem is consulting on three policy options for addressing financeability issues:[75]

- Option A: Adopting a nominal return instead of a real return which will bring cash-flows forward
- Option B: Putting the onus on companies, e.g. to de-gear
- Option C: Introducing a licence backed revenue floor

In this section, we review Ofgem's proposed approach and three options. We conclude that if a lower cost of equity at RIIO-2 leads to a credit rating below an average of A and BBB (the rating that we expect to form the basis for the cost of debt allowance), then the onus is on Ofgem to reconsider its proposed cost of equity and the rating of the index underpinning the cost of debt mechanism. Ofgem's proposed solutions do not address the fundamental problem of inconsistency of its proposals.

This chapter is structured as follows:

- Section 4.1 explains the rationale for the financeability test, and the need for Ofgem to demonstrate the integrity of its revenue proposals, and therefore responds to Ofgem's Option B (putting the onus on companies). We also set out the relevant ratios and thresholds.
- Section 4.2 discusses how Ofgem's option A, setting the price control based on a nominal WACC, would lead to higher bills and financing costs.
- Section 4.3 explains that Ofgem's option C, revenue floor, ignores the fundamental issue and is impracticable.
- Section 4.4 draws conclusions.

4.1. Contrary to Ofgem's Option B, the onus should be on Ofgem to ensure consistency of its financial proposals

Under its option B, Ofgem considers that the onus should be on companies to address notional or actual financeability constraints, for example, through an equity injection. It also raises the prospect of changes to regulatory parameters such as capitalisation rates to address

74 Ofgem (March 2018), op. cit., p.93.

75 Ofgem (March 2018), op. cit., p.93.

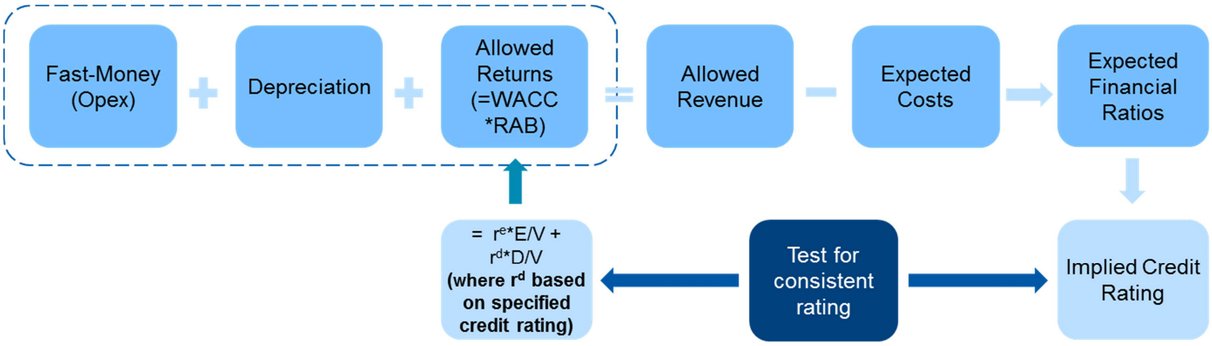
credit metrics, although Ofgem acknowledges that such an approach may be discounted by rating agencies (RAs).[76]

We disagree that the onus should be on companies. In this section, we set out why the onus should be on Ofgem to ensure the consistency of its proposals.

4.1.1. A financeability test is a check on the consistency of the allowed return and the outturn financial metrics

A financeability test should assess whether a licensee is able to finance its operations on reasonable terms and consistent with the terms assumed in the allowed return element of its allowed revenues. Specifically, the test should establish whether there is consistency between the credit rating underpinning the notional cost of debt in the allowed rate of return and the credit rating implied by the projected financial ratios under a notional financing structure, as shown in Figure 4.1.

Figure 4.1
The financeability test should test consistency between the allowed rate of return and the expected financial metrics



Source: NERA illustration

If the projected financial ratios imply that the regulated business cannot raise debt finance on the terms (i.e. credit rating) as assumed in the allowed rate of return, the regulator has not set overall revenues that allow the company to have a reasonable prospect of recovering its costs. In these circumstances, the allowed rate of return cannot be considered reasonable.

Regulators conduct such tests to ensure that companies are able to finance their activities, a standard regulatory objective. For example, at ED1 Ofgem referenced its Principal Objective which is to protect consumers, and under which it must have regard to the need to secure that companies can finance their activities. [77]

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[76] Ofgem (March 2018). RIIO-2 Framework Consultation, p.97.

[77] Ofgem stated: "*3.1. Our principal objective is to protect the interests of existing and future consumers. In carrying out its functions in accordance with the principal objective, the Authority must also have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations on them. This means that, in setting price controls, we should have regard to the ability of network companies to secure financing in a timely way*

In terms of solutions, if the projected ratios are weaker than the credit rating underpinning the cost of debt allowance at RIIO-2, then the direct resolution is for Ofgem to increase the cost of equity allowance to ensure the integrity of the revenue proposals. An alternative solution may be to set the cost of debt indexation mechanism based on an index which corresponds to the projected rating (e.g. BBB). In relation to the latter, Ofwat determined a BBB rated iBoxx index for the Thames Tideway Tunnel based on projected BBB credit metrics and rating for the infrastructure provider to ensure the integrity of the framework. [78, 79]

4.1.2. Target ratio levels should be consistent with rating for allowed cost of debt index

Ofgem stated that it intends to use gearing (net debt to RAV), and the post-maintenance coverage interest ratio (PMICR) as the key credit metrics for its financeability assessment at RIIO-2, while it will also consider other metrics including funds from operations (FFO) interest cover, and retained cash-low (RCF) to net debt.[80]

Moody’s rating methodology provides a relatively mechanistic approach to rating determination, which Ofgem intends to draw on to conduct the financeability test at RIIO-2. The target financial ratios consistent with an A and BBB rating used by Moody’s are set out in Table 4.1 below.

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and at a reasonable cost in order to facilitate the delivery of their regulatory obligations. 3.3. We generally equate financeability with an ability to maintain an investment grade credit rating. The first stage of our financeability assessment is therefore to consider how our proposed price controls will affect credit ratings.” (Source: Ofgem (July 2014), RIIO-ED1 Draft determination for the slow-track electricity distribution companies - Financial Issues, para 3.1, p.16.)

78 Thames Tideway Tunnel Project Licence, August 2015, p.72. Link: https://www.ofwat.gov.uk/wp-content/uploads/2015/10/lic_lic_baz.pdf

79 The Utility Regulator in Northern Ireland determined a BBB rated iBoxx index for PNG and firmus at the most recent reviews (GD17), as well as a NIE at RP7. These decisions were based on an assessment of credit risk, and an assumption that BBB represented the efficient notional rating. See for example, UR (November 2016) Price Control for NI GDNs, Chapter 10. Link: https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/2016-09-15_GD17_Final_Determination_-_final_0.pdf

80 Ofgem (March, 2018), op. cit., p.94.

Table 4.1
Target Credit Rating Ratios Consistent with Moody's A and BBB Credit Score

Financial metric	A	Baa
Adjusted Interest Coverage Ratio:	2 - 3.5x	1.4 - 2x
OR	OR	OR
FFO Interest Coverage	4 - 5.5x	2.8 - 4x
Net Debt / RAB OR Net Debt / Fixed Assets	45 - 60%	60 - 75%
FFO / Net Debt	18 - 26%	11 - 18%
RCF / Net Debt	14 - 21%	7 - 14%

Source: Moody's (March 2017), Rating Methodology: Regulated Electric and Gas Networks, p.19

At ED1, although focusing closely on Moody's methodology, Ofgem considered a wider range of financial metrics than those used by Moody's. The list of financial metrics together with thresholds for investment grade credit rating as considered by Ofgem at ED1 are set out in Table 4.2 below.

Table 4.2
At ED1, Ofgem conducted its financeability test based on BBB ratio thresholds

Financial metric	Threshold
FFO interest cover ratio	2.5 min
Adjusted interest cover ratio, or PMICR	1.4 min
FFO / Net Debt	8% min
RCF / Net Debt	5% min
Net Debt / RAV	80% max
RCF / Capex	0.5 min
Regulated equity / EBITDA	5.5 max
Regulated equity / PAT	18 max
Dividend cover ratio	1.0 min

Source: Ofgem, RIIO-ED1 Draft determination for the slow-track electricity distribution companies, Table 3.1, p. 17.

By comparison with Table 4.1, the thresholds for ratios applied by Ofgem at ED1 appear to be closer to BBB rating rather than average A and BBB, and therefore appear inconsistent with its notional cost of debt assumption (based on an average of A and BBB rated iBoxx bond indices). At RIIO-2, Ofgem should ensure that the projected ratios, alongside the qualitative factors considered by Moody's in determining the overall credit rating for energy networks[81], are consistent with an average of A and BBB ratings assuming that this is the basis for the cost of debt indexation mechanism.

In principle, the assumed initial gearing should be consistent with the gearing assumed by the regulator in determining the WACC. At ED1, Ofgem's central assumption was to test financeability based on the notional debt position of DNOs, on grounds that it is up to DNO owners to resolve issues that may arise if their actual position significantly differs from notional. Similarly, Ofgem's baseline scenario assumed debt costs consistent with the cost of debt allowance. [82]

Where a company's actual cost of debt differs from the regulators' allowance (e.g. where the regulator has allowed an industry wide embedded debt cost rather than a company specific cost of debt), this provides a rationale for using companies' actual debt costs in the financeability test. For example, at ED1, Ofgem considered financial ratio sensitivities based on actual gearing levels and actual debt costs,[83] and similarly the CMA in the case of Bristol Water and NIE considered actual gearing and actual debt costs.[84]

Finally, as well as Moody's rating methodology, Ofgem should also apply S&P ratings methodology which is the other principal rating agency for GB utilities.

4.1.3. Financeability testing should be undertaken against plausible downside scenarios

At ED1, Ofgem's central assumption was to test financeability based on the notional debt position of DNOs, as well as extending the analysis to take account of the DNO's actual embedded debt positions (as noted above) [85]. Ofgem also considered financeability under a range of interest rate scenarios, modelling both changes to company interest costs and allowances, in order to assess resilience to possible downside scenarios.[86]

Likewise, the financeability assessment at RIIO-2 should also include testing based a range of different interest rate scenarios including plausible downside scenarios.[87] As well as interest

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81 The sub-ratings associated with the qualitative factors may come under pressure where ratings agencies perceive that changes threaten companies' ability to recover costs, and undermine the credibility and predictability of the regime, as we discuss in section 5.4.4.

82 Ofgem (July 2014), RIIO-ED1 Draft determination for the slow-track electricity distribution companies - Financial Issues, para 3.9, p.17.

83 Ofgem (July 2014), RIIO-ED1 Draft determination for the slow-track electricity distribution companies - Financial Issues, para 3.10 – 3.11 and Table 3.2, p.17. Also see Ofgem (July 2014), RIIO-ED1 Draft determination for the slow-track electricity distribution companies - Overview, para 5.25, p.42.

84 See for example, CMA (2015) Bristol Water plc. Link: https://assets.publishing.service.gov.uk/media/56279924ed915d194b000001/Bristol_Water_plc_final_determination.pdf

85 Ofgem, Draft Determination for RIIO-ED1 – Financial Issues, para 3.9.

86 Ofgem (2014) Final Determination for RIIO-ED1, Para 5.24 Link: https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_overview_-_updated_front_cover_0.pdf and para 3.9-3.10 of Draft Decision.

87 Ofgem, RIIO-ED1 Draft determination for the slow-track electricity distribution companies.

costs, the stress testing should encompass plausible downside scenarios for totex, where downside scenarios should take into account any difference between Ofgem's view of efficient costs and companies' business plan submission.

4.1.4. Assumed dividend pay-out and variation in capital structure

Both Ofgem (RIIO ED1 for slow track DNOs) and CMA (NIE 2014) have modelled dividend pay-out ratios at 5 per cent of the equity portion of the RAV. The CMA's rationale for this assumption is that an efficient licence holder would implement a dividend pay-out policy consistent with the post-tax cost of equity reflected in the WACC determination, i.e. around 5 per cent.[88]

The revenue allowance at RIIO-2 should also provide for equity issuance costs to achieve the notional gearing at the start of RIIO-2 where this is changed relative to previous reviews. That is, Ofgem should provide for issuance costs to allow companies to de-gear to the lower notional gearing. Ofgem should also continue to provide for equity issuance costs to maintain the notional rating during review, e.g. where companies' investment programme would otherwise increase gearing above the notional level. As at previous reviews, Ofgem should allow for the cost of such (notional) equity injections, e.g. at RIIO-1, Ofgem allowed for an equity issuance cost of 5 per cent.[89]

4.1.5. Ofgem correctly recognises that short-term fixes may not be supported by RAs

Under its proposed option B, Ofgem notes that Ofwat has considered changes to depreciation and capitalisation rates in order to ensure financeability at PR19, but acknowledges that in early discussions the RAs have said that they will "*discount such approaches*".[90]

We agree: there may be constraints from rating agencies (RAs) on regulators ability to use such short-term fixes to address financeability constraints, where the fix simply postpones problems to future price controls.

Specifically, in the context of its proposed switch to CPI indexation, Ofwat has stated that companies may consider adjustments to PAYG to off-set any negative bills impacts. However, PAYG adjustments – which move away from the "natural" expense/ capitalisation rate –may not be recognised by Rating Agencies. For example, Moody's has stated that that "*use of regulatory levers to offset bill increases could erode confidence in the regulatory framework. […] if revenue deferrals are imposed on companies such that the "allowed"*

88 CMA (2014) NIE plc, para 17.39. Link: https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

89 See for example, Ofgem price financial model (PCFM), https://www.ofgem.gov.uk/system/files/docs/2017/11/et1_pcfm_november_2017.xlsm

90 Ofgem (2018) op. cit., p. 96

return can never be realised, our current view of the regulatory framework could be weakened."[91]

Moody's has also questioned the potential use of short-term financial levers in the case of PNG, which has substantive revenue deferral as a consequence of the need to smooth prices in the early years of the project, and consequently weak credit ratios. In this case, Moody's states that: "*[...] although the AICR is likely to rise if financial levers are used [...] we would not regard credit quality as having been improved.*" 92

4.1.6. Conclusions on Ofgem's Option B

In conclusion, under option B, Ofgem asks whether the onus should be on companies to address financeability issues, e.g. through an equity injection and associated de-gearing to achieve investment grade credit metrics. As we explain in this section, we believe the onus should be on Ofgem to ensure the consistency of its financial proposals at least on a notional basis, and potentially also on an actual basis where the notional cost of debt allowance is lower than companies' actual debt costs. It is up to companies to ensure that they maintain an investment grade credit rating based on their *actual capital structure*, and consistent with licence requirements, but only once Ofgem has demonstrated the integrity of the price control proposals on a *notional* basis.

4.2. A nominal based WACC may improve financeability, but should be considered in a wider policy context (option B)

A switch to a nominal based WACC regime would bring cash-flows forward which could potentially improve credit metrics, but introducing such a substantial change to the existing regulatory framework should be considered in a wider policy context, as opposed to being adopted as a "fix" to any existing financeability concerns. The potential downside implications include:

- **Impact on network charges (short-run)**: The introduction of nominal WACC would lead to a one-off increase in network charges. Such a substantive increase may not be justified from the customers' perspective. This increase could be in theory offset by adjusting other regulatory parameters (e.g. capitalisation rates). However, any such adjustments would remove the benefit of cash being brought forward in the first place and hence lead to no improvement in financeability and may also be viewed negatively by rating agencies as undermining the confidence in the regulatory framework (as set out in section 4.1.5).
- **Inter-generational equity (long-run impact on network charges)**: A switch to nominal WACC also raises concerns regarding inter-generational equity. A nominal WACC approach implies that in a steady state, the value of the asset base is written down in real terms over time, which in turn implies that current customers would pay a higher price than future customers for receiving the same service. This may not be considered fair from an inter-generational equity perspective.

[91] Moody's (January 2016), Transition to CPI creates risks for water and energy networks, p.1.

[92] Moody's (January 2016), Transition to CPI creates risks for water and energy networks, p.6.

- **Impact on risk from removing RPI-hedge for ILD**: A switch to nominal WACC would remove the RPI-inflation hedge offered by the current regulatory regime, which companies have used to issue RPI-linked debt. This in turn could increase companies' financing costs (e.g. through companies having to hedge their existing RPI exposure using RPI-nominal swaps).

4.3. A licence backed revenue floor avoids the fundamental issue with poor metrics, and is impracticable (Option C)

4.3.1. Ofgem identifies two variants for a revenue floor

Under option C, Ofgem proposes to limit the downside of the price control package to give greater assurance that debt costs will be met. It states that this would involve "*introducing a licence condition that sets a floor below which company revenue would not be allowed to fall*", and that the floor could be set at a level that "*would allow a notionally geared company to more easily service interest payments equal to the cost of debt allowance*."[93]

Ofgem considers that the revenue floor could secure higher value for consumers, as "*a positive impact on credit ratings could reduce the rate of interest lenders would require. Similarly, reducing default risk could provide further downward pressure on rates.*"[94] It identifies two variants:

- Variant 1: *Maximum penalties*: Places a limit on the value of underperformance, e.g. by determining that the return on regulated equity (RoRE) would not fall below a pre-defined level, say, 1 per cent;
- Variant 2: *Minimum coverage ratios*: E.g., Ofgem would provide a minimum revenue to ensure a particular level for a financial ratio such as the AICR

In either case, Ofgem notes that the additional revenue required to meet debt payments would need to be recovered from consumers at a future date, e.g. through a reduction in the value of RAV or reduced revenues.

4.3.2. The approaches ignore the fundamental problem that financeability identifies

Our main concern with Ofgem's proposed revenue floor is that it avoids the fundamental problem: where expected credit metrics correspond to a rating which is below the rating assumed in the allowed return, the allowed return should be reconsidered. That is, Ofgem's proposals ignore the inconsistency problem and the reason for the financeability test.

We also consider the approaches are impracticable:

- Ofgem intends that any advanced revenues are recovered over future years: the approach simply defers financeability issues to subsequent years. It also suggests that the revenue

93 Ofgem (2018) op. cit., p. 96

94 Ofgem (2018) op. cit., p. 96

floor would provide little value to creditors, as in theory companies could rebalance cash-flows, e.g. itself borrow against future cash-flows as opposed to effectively borrowing from customers.

- The revenue floor may provide some insurance in the event of adverse cost or incentive performance. |However, cost performance is observed with a lag, and accounted for in the price control financial model (PCFM) with a lag of at least two-years. These timelines may be too long to provide adequate protection for creditors.
- Ofgem has an objective to simplify the framework, but a revenue floor provides for further complexity and regulatory cost.

4.4. Conclusions

The financeability test is a test of consistency between the rating underpinning the allowed rate of return and the rating implied by the forecast financial metrics. If the financial metrics provide a credit rating below an average of A and BBB, then this provides a clear rationale for Ofgem to reconsider the cost of equity and the rating of the index underpinning the cost of debt mechanism.

As Ofgem acknowledges short-term fixes, e.g. bringing forward cash-flows, do not resolve the underlying long-term issue and any arbitrary changes to regulatory levels (e.g. capitalisation rates) may not be recognised by RAs. Ofgem’s other proposed fixes – nominal returns – represent fundamental changes to the existing regulatory framework and should be assessed in a wider policy context than purely considering financeability implications (including higher short-term bills and inter-generational equity considerations).

5. Ensuring Fair Returns

In its framework document, Ofgem consults on a number of potential changes aimed at ensuring fair returns to energy networks.[95] In particular, Ofgem expresses concern that returns have been high in the gas distribution and electricity transmission sectors, where the main driver has been cost outperformance. In the electricity distribution sector, it notes that performance against the interruptions incentive provides the main driver.

Ofgem considers that although costs can increase above the forecast allowance, it believes that companies generally face a greater likelihood that risks will run in their favour rather than against them.[96] It states that its experience of RIIO-1 and previous price controls is that irrespective of the apparent reasonableness of the price control, companies may still be able to outperform against the baseline assumptions and earn high returns. Ofgem therefore identifies a number of measures that could guard against higher returns, comprising:[97]

- A hard cap/floor
- Discretionary adjustments
- Constraining totex and output incentives
- A RoRE sharing factor
- Anchoring returns

In this section, we consider the level and sources of outperformance at RIIO-1 in comparison with the water and other partly regulated sectors. We identify options that could promote fair returns without undermining the efficiency properties of the RIIO regime, namely around shortening the price control, real price effect (RPE) indexation, and sculpting returns, as Ofgem has proposed in its framework consultation. However, we consider that Ofgem's other options, such as hard caps and collars, discretionary adjustments, constraining incentives, and anchoring returns will increase regulatory costs and risk, and/or dampen incentives, in contrast to the RIIO objectives.

The chapter is structured as follows:

- Section 5.1 summarises the potential issues with GD1 that need to be addressed whilst retaining the central objectives of the RIIO framework
- Section 5.1considers the cost performance by GDNs and energy networks over RIIO-1 more widely relatively to other regulated and non-regulated sectors
- Section 5.3 explains the principal reasons for strong cost performance over RIIO-GD1
- Section 5.4 sets out potential options to ensure fair returns, evaluating Ofgem's options
- Section 5.5 concludes

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95 Ofgem (March 2018) op. cit., p. 100

96 Ofgem (March 2018) op. cit., para 7.110,.p. 100

97 Ofgem (March 2018) op. cit., para 7.122,.p. 103

5.1. Any changes to the regime should be consistent with RPI-X "root-and-branch" review which strongly supported incentive based regulation

5.1.1. The RIIO model brings substantive benefits

In 2010, Ofgem concluded a "root-and-branch" review of the RPI-X framework, and concluded firmly in support of an incentive based regime with up-front/ex-ante efficiency incentives. For example, Ofgem concluded that:[98]

> *The RIIO model has taken the elements of the old RPI-X framework that work well, adapted other elements to ensure they are focused on delivery of a sustainable energy sector and long-term value for money, and added elements to encourage the radical measures needed in innovation and timely delivery.*

As set out in the RIIO decision documents and handbook, the original objectives of the RIIO framework focus on improving cost and output performance through enhanced incentives. The objectives include:

- *To promote cost efficiency, notably by avoiding ex-post adjustments (other than through symmetric up-front incentive rate)*
- *To promote an output based approach, with financial rewards/penalties associated with companies' performance*
- *A transparent regulatory framework, where there is a clear understanding of the outputs delivered and rewards/penalties for doing so*
- *High returns for good performers on costs and outputs, and low returns for poor performers*
- *Promoting investor confidence to secure efficient financing*

In terms of quantifying the potential benefits of the RIIO regime, the impact assessment supporting the RIIO decision identified potential consumer benefits from "efficiency savings" alone of between £290m and £415 m per annum under the central scenario, and an overall saving of around £1 billion relative to the RPI-X regime. [99]

These efficiency savings of up to £1 billion result in equivalent reductions in customer bills given that the RIIO framework includes provision for sharing of efficiency improvements within review through the IQI sharing factor, and then passing through the entire benefit to customers of any savings at review where allowed revenues are reset based on companies' actual costs.

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98 Ofgem (2010) Handbook for implementing the RIIO model, Summary. Link: https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbookpdf

99 Source: Ofgem (July 2010) Impact Assessment, p. 6. Link: https://www.ofgem.gov.uk/ofgem-publications/51904/impact.pdf

5.1.2. Potential changes should be aligned with the RIIO principles

In identifying potential changes to the existing framework, we consider that the RIIO objectives remain valid and there is no requirement for a further “root-and-branch” review. However, there are concerns expressed around about RIIO-1 performance that need to be addressed. We summarise these as:

- The level of returns are too high with an element of the return relating to GDNs bearing market risk
- There is a lack of dispersion in companies’ returns
- There is a lack of transparency around the reason for outperformance, and customer benefits, e.g. what element relates to improved cost and output performance

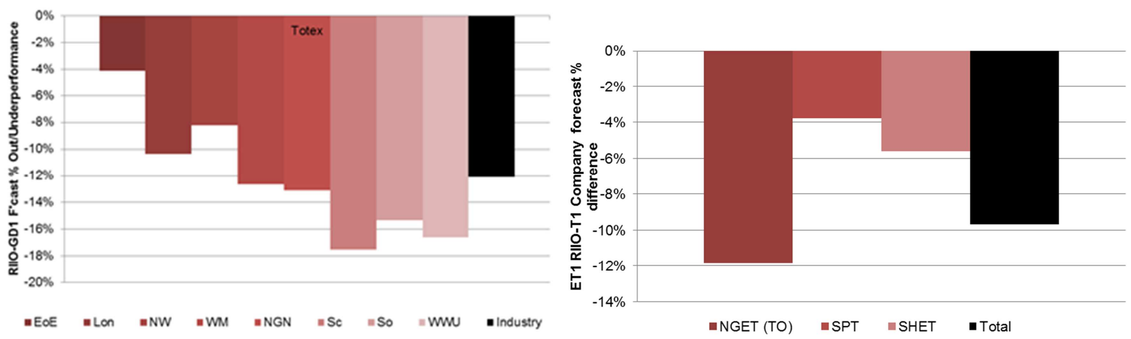
We first consider the evidence on the level of returns for RIIO-1 (section 5.2) and the reasons for the cost performance (section 5.3). We then consider how the issues around level and transparency of return could be addressed whilst preserving the incentive properties of the RIIO regime (section 5.4).

5.2. RIIO-1 variation in returns is not unreasonable compared to other regulated and non-regulated sectors

5.2.1. There is no systematic outperformance across RIIO-1 price controls

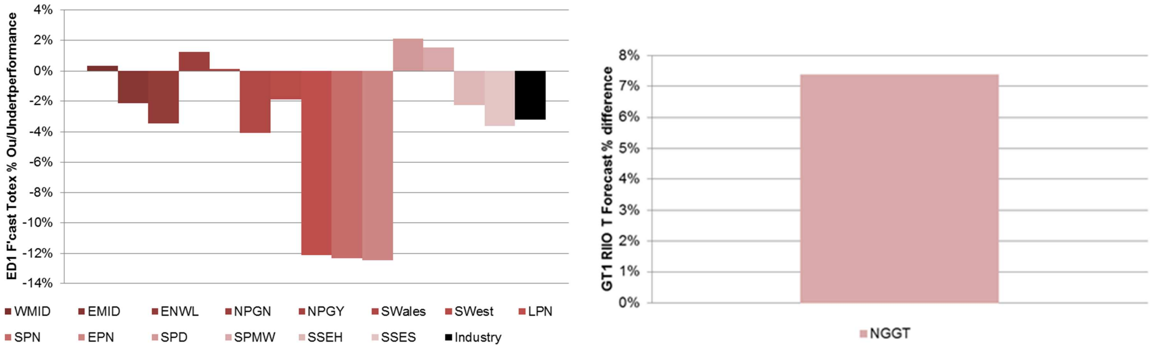
As set out in Figure 5.3, the gas distribution and electricity TOs expect to outperform the price controls set in 2013 at their respective reviews. However, as we explain in section 5.3, the outperformance is explained by the relatively weakness of the economic recovery and commodity prices, and the fact that framework assigns market risks to the energy networks. For electricity distribution, the picture is more mixed – with five licenses expecting to underperform against totex allowances. NGGT also expects to substantively underperform.

Figure 5.1
GDNs and TOs expect to outperform on totex over RIIO-1, having benefitted from bearing market risk



NERA analysis of RIIO-GD1 2016/17 accounts

Figure 5.2
For ED, totex performance is mixed. NGGT expects substantive underperformance



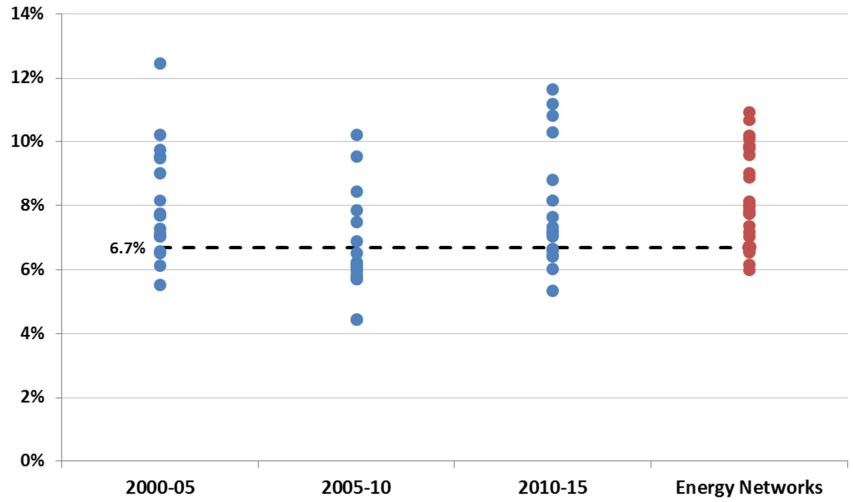
NERA analysis of RIIO-T1 and RIIO-ED1 2016/17 accounts

5.2.2. Water sector RORE is similar to RIIO-1

We have analysed cost performance in the water sector for the three regulatory periods over the period 2000-15. [100] The analysis shows that water company performance lies in the range of 4 to 12 per cent real post tax for most periods, and is similar to expected energy sector performance over RIIO-1, taking into account all energy companies.

100 The analysis includes cost performance only, and excludes performance related to customer service measures, and therefore understates RORE.

Figure 5.3
Water company cost performance lies in range of 4 to 12 per cent (real, post-tax), in line with expected cost performance over RIIO-1[101]



Source: NERA analysis of water and energy network company data. Note, we have set out the returns based on an assumed allowed return of 6.7 per cent real return on equity for direct comparison with GDN returns for RIIO-GD1.

5.2.3. Returns to telecoms and transport sectors are high and variable

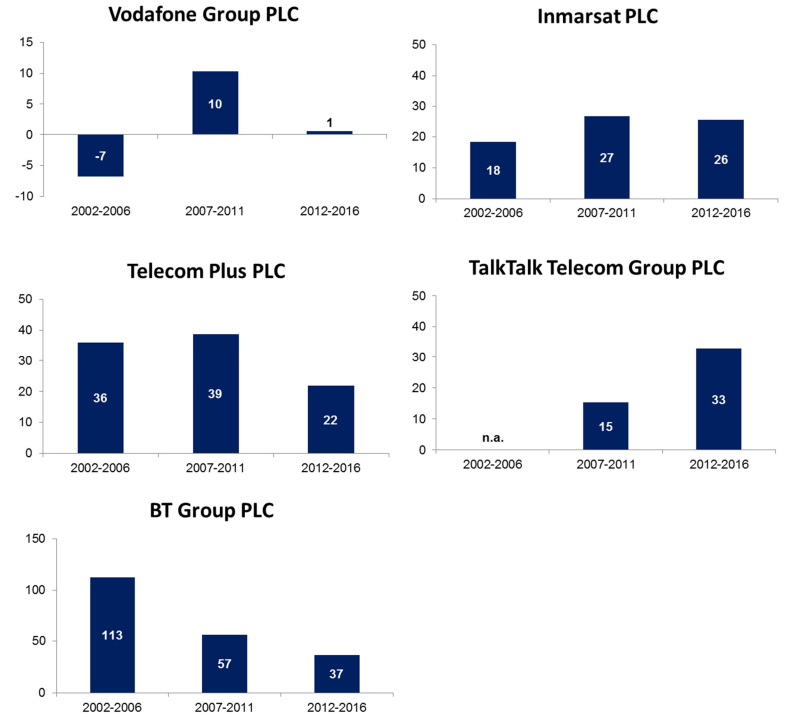
We have also reviewed evidence for telecoms and transport sectors which will operate in both regulated (e.g. train and bus franchise) as well as non-regulated markets (e.g. competitive telecom retail markets), and which have similar cost structure and demand characteristics as energy networks. We have calculated the normalised return on total common equity, where the return is adjusted for abnormal and exceptional items, as our analogous measure to RORE.[102] We have calculated average returns over a five year period to smooth for single year variation in outperformance, and to correspond to a price control period.

Overall, our analysis suggests shows that the return on book equity at the top-end is far greater than observed for energy networks.

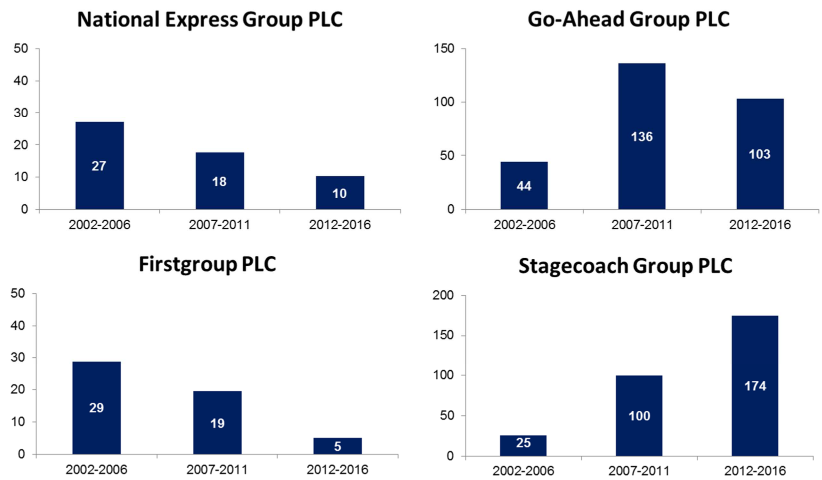
[101] An alternative source for water companies' historical RORE performance since PR99 can be found in Ofwat's PR14 risk and reward guidance document: https://www.ofwat.gov.uk/wp-content/uploads/2015/11/gud_tec20140127riskreward.pdf (page 42). Ofwat's analysis shows greater RORE variation than our figures. However, it is not clear to us that Ofwat's RORE data is valid. It appears that its analysis shows the high/low RORE variation observed in any single year, and therefore the figures are therefore likely to be substantively affected by capex timing as opposed to out or underperformance per se, and are therefore a flawed measure of shareholder return. By contrast, our data takes performance over the whole regulatory period.

[102] We acknowledge that book equity will be recorded in historical cost accounting terms, except for periodic valuations such as for land and buildings, and therefore our ROE measure may overstate the real (economic) return.

Figure 5.4
Return on book equity is high and variable in the telecoms and transport sectors
a) Telecoms



(b) Transport



Source: NERA analysis of Bloomberg data

5.3. Explaining GDN cost performance at RIIO-1

Energy network cost performance can be separated into two factors: the improvements in cost efficiency of the network relative to those assumed by Ofgem at review, as well as performance arising from factors where energy networks bear risk, and where they may enjoy windfall gains or incur windfall losses. The types of risk that energy networks bear are varied. For example, energy networks bear risk in relation to general economic conditions, notably in relation to input prices, as well as other factors, such as weather and government and wider regulatory risks, e.g. assumptions around the up-take of the smart metering programme.[103]

We consider that it is useful to disaggregate performance over RIIO-1 by these two categories, as they require different regulatory responses. For example, to the extent that cost performance has been driven by cost efficiency, the incentive properties of the existing framework should be retained (and indeed enhanced) as cost efficiencies result in lower long-term costs. By contrast, cost out or under-performance due to energy network bearing market and other risks raises questions about the correct risk allocation between companies and consumers at RIIO-2.

5.3.1. Ofgem's view of cost performance

In its recent RIIO report for GDNs, Ofgem identifies a number of areas where GDNs have improved cost performance that led to outperformance of the price controls. For example, it notes that GDNs have outperformed repex cost allowances by around 19 per cent compared to 12 per cent on totex more generally, which may be explained by the strong incentive properties of the new GD1 arrangements as well as factors where GDNs bear risk.

For example, innovative use of robots to avoid digging and reinstatement; renegotiating of working practices; and, improved work planning processes facilitated by the greater use of IT have all contributed to improvements in cost performance.[104]

Changes to the regulatory framework have also incentivised GDNs to deliver the requisite risk reduction at lower cost. For example, the GD1 framework allows GDNs to prioritise the abandonment of higher risk yet lower cost iron mains. As a consequence of replacing higher risk (e.g. higher failure rate) mains, the programme has led to reductions fractures, leaks and repairs and lower opex and capex costs.[105] Such improvements in cost and service performance should also be viewed as improvements in efficient delivery, arising from the greater focus on output regulation (e.g. risk reduction) as opposed to Ofgem prescribing inputs (mains abandoned).

However, Ofgem also notes that an element of outperformance is related to risks that are borne by GDNs. For example, it considers that GDNs have outperformed because of relatively mild winters resulting in reduced fractures and repairs. It also considers that weaker economic conditions have led to fewer connections and therefore connection and other asset reinforcement costs than envisaged in setting the control.[106]

Ofgem also notes that GDNs bear risk in relation to real price effects (RPEs), and GDNs have outperformed the regulatory assumptions because of weaker domestic economy, and weaker international commodity prices than reasonably foreseen at GD1. As we explain below, we

[103] Similar, in its recent annual report, Ofgem has categorised outperformance as follows: efficiency, external factors, and other provisions. See: Ofgem (2017) RIIO-GD1 Annual Report, 2016-17, p. 16.Link: https://www.ofgem.gov.uk/system/files/docs/2017/12/riio-gd1_annual_report_2016-17.pdf

[104] Ofgem (2017) op. cit., p. 18.

[105] Ofgem (2017) op. cit., p. 17.

[106] Ofgem (2017) op. cit., p. 19.

consider that this element is likely to explain a substantive element of the cost outperformance over GD1.

5.3.2. GDNs bear market risk and have benefitted from weaker input prices over GD1

We have considered the extent to which GDN's cost outperformance is related to the market risks borne by the industry at review. As noted above, the principal risk is in relation to real price effects (RPEs), where Ofgem makes assumptions at review based on short-term forecasts and extrapolating historical trends.[107]

The principal input price risk borne by GDNs relates to labour costs. Ofgem estimates that 64 per cent of GDNs costs are labour related.[108] At GD1, Ofgem set an allowance based on the short-run HMT forecast for wage costs, and beyond the forecast period, based on the long-run historical trend growth rate for a number of labour specific wage series.[109]

We have compared Ofgem's allowances for labour costs, as well as material costs, with the outturn values to date for the indices that Ofgem used at GD1 to set allowances. Overall, we estimate that weaker input prices, due to weaker income growth in the GB labour market and weaker commodity prices could explain a material element of the expected industry totex outperformance of 12 per cent[110], although there is uncertainty over how input prices will continue to evolve and we cannot draw firm conclusions until the end of GD1.

5.4. Potential remedies to ensure fair returns

Any changes to the RIIO framework should focus on rebalancing the risks borne by GDNs relative to customers, whilst preserving the incentive properties of the RIIO framework to ensure continued strong cost efficiency performance (as summarised in section 5.1).

We consider that there are three issues that Ofgem could consider in terms of rebalancing risk, and mitigating out (and under) performance relating to market risks. These are RPE indexation; structuring the incentive rate; and, a shorter price control. These are all options set out in Ofgem's recent framework consultation, and Ofgem explicitly sets out its intention to "index cost categories where feasible"[111], and adopt a 5-year price control.[112]

By contrast, we do not consider that Ofgem's other options, and notably "anchoring of returns" is consistent with an incentive based regime, is not practicable, and will increase risk and financing costs. We discuss these issues below.

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[107] See: Ofgem (December 2012) RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Link: https://www.ofgem.gov.uk/ofgem-publications/48159/5riiogd1fprpedec12.pdf

[108] Ofgem (December 2012) RIIO-T1/GD1: Real price effects and ongoing efficiency appendix p.11. Link: https://www.ofgem.gov.uk/ofgem-publications/48159/5riiogd1fprpedec12.pdf

[109] Ofgem (December 2012) op. cit., p.8.

[110] Ofgem (2017) op. cit., p. 18.

[111] Ofgem (March 2018) op. cit. para 7.116, p.102

[112] Ofgem estimate that eight-year totex allowances would have been £714 million lower across the industry had Ofgem used indexation for RPEs as opposed to setting ex ante RPE allowances at GD1. Ofgem (March 2018) op. cit. chapter 4.

5.4.1. RPE indexation

Under the current approach to RPEs, Ofgem sets an *ex ante* allowance at the beginning of the regulatory period, without any provision for updating over time as new information becomes available on outturn/expected input price inflation. This places all risk on uncertain input price growth on energy network.

An alternative approach would be to link all, or an element of, energy networks allowed costs to an index other than RPI (either annually, or by the use of an *ex post* reconciliation). Indeed, Ofgem consulted on such an approach at ED1. Such an approach requires identification of an index that accurately reflects changes in the input prices incurred by energy networks, which may be challenging but is required where Ofgem sets an ex ante allowance under its current approach.

A particular attraction of this approach is that it preserves the incentive properties of the current regime: as long as the input price index is independent of energy network costs, networks retain the same incentive to minimise costs over the regulatory period. Ofwat has previously indexed allowances to indices besides RPI as is also common practice in the US. price indices are common in commercial contracts, as we describe below.

5.4.1.1. Regulatory precedent

Until the most recent price control, Ofwat used an index of capital costs to provide an *ex post* correction to bring water companies allowed costs in line with movements in the index. Since this correction is NPV neutral, this mechanism is equivalent to an annual indexation of one element of allowed costs to an index other than RPI.

Ofwat used the Construction Price Index (COPI) to update companies' capital expenditure allowances at regulatory reviews (relative to the real input price allowed at review).[113] The evidence suggests that updating allowances for water companies at the last review (2010-15) led to a material correction to companies' capex cost performance, given the weak economic condition and the pro-cyclicality of COPI. For example, our analysis for Anglian Water shows that its capex outperformance was 21 per cent prior to the adjustment for COPI, and reduced to 13 per cent following the ex post application of the input price adjustment. [114]

However, for the most recent price control (2015-20), Ofwat has decided to discontinue the use of COPI.[115] This decision has been made in the context of Ofwat's broader focus on total

[113] Ofwat (2011), *Information Note*, accessible at http://www.ofwat.gov.uk/regulating/prs_in1108copi.pdf.

[114] The calculation is based on AWG's capex outperformance at AMP5 before and following the correction for input price adjustments (referred to as the Notified Index). Ofwat's Notified Index measured construction sector (negative) real price effects, based on differences between ONS Construction Output Price Index (COPI) and RPI inflation rates. Source: Ofwat (July 2013), Setting price controls for 2015-20 – final methodology and expectations for companies' business plans, p. 155.

[115] See for example, Ofwat (2013), *Setting price controls for 2015-20 – final methodology and expectations for companies' business plans*, July 2013, page 155.

expenditure, rather than splitting expenditure into capital and operating expenditure for the purpose of regulation.

US regulators also have a long history of indexing allowed costs and revenues to indices other than general price inflation indices. For example, the Federal Energy Regulatory Commission (FERC) allows for increases in interstate pipelines based on a producer price index (PPI) for finished goods.[116]

5.4.1.2. Use of indexation in private contracts

Indices of production costs, such as producer price indices (PPIs) and price adjustment formulae indices (PAFIs), are frequently used for linking a contractual price to the costs of honouring the contract. Two examples of organisations that produce such indices are the British Electrotechnical and Allied Manufacturers' Association (BEAMA), and the Building Cost Information Service *of* Royal Institution of Chartered Surveyors (BCIS).

BEAMA produces indices that are "*primarily designed for use with manufacturing contracts but now have a much wider application*".[117] These include:

- Variation of contracts prices;
- Annual variations to service and maintenance contracts; and
- Updating the contract prices to a new base date.

BCIS produces price indices that are predominantly used in construction and maintenance sectors. In particular, BCIS maintains Price Adjustment Formulae Indices (PAFI) that are "*used in conjunction with the Formula Methods of adjusting building, specialist engineering and civil engineering contracts to allow for changes in the costs of labour, plant and materials.*"[118]

The indices the BCIS maintains cover a wide range of products. Indeed, BCIS maintains the COPI index that is used in the water industry.

5.4.2. Sculpturing the incentive rate

One option to mitigate market risk is to sculpture the incentive rate such that at certain points a greater share of outperformance (and underperformance, if symmetric) is passed-through to customers. The sculptured incentive rate could apply to both totex and output incentives. There are recent examples of sculptured incentive rates in the water sector:

- The Infrastructure Provider (IP) for the Thames Tideway Tunnel (TTT) is subject to sculptured incentive rates; in this case protecting it from cost overrun risk. Specifically, the project is subject to a 40 per cent sharing factor up to a so-called Threshold Outturn.

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[116] FERC (December 2015) Five-year review of oil pipeline index. Link: https://www.ferc.gov/industries/oil/gen-info/pipeline-index/RM15-20-000.pdf

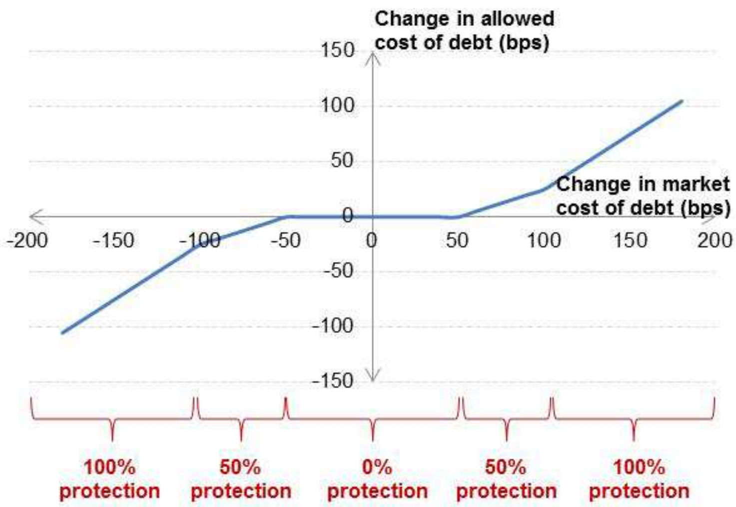
[117] See http://www.beama.org.uk/

[118] See http://www.rics.org/uk/knowledge/bcis/

[119] In the event that project costs are forecast to exceed the Threshold Outturn level, the Project Licence[120] allows the IP to make a request for approval for further cost allowances.

- The IP is also subject to a sculptured incentive rate in relation to the cost of debt allowance. In this case, the IP bears full risk of deviations in debt costs of up to 50bps relative to the debt cost at project commencement, 50% of the risk for deviations between 50 and 100 bps and no risk for deviations beyond 100 bps. The dead-bands provide only partial protection to the IP from movement in debt costs up to 100bps, and full protection beyond 100 bps, as set out in Figure 5.5 below.

Figure 5.5
The TTT cost of debt mechanism provides partial protection for changes in market cost of debt up to 100 bps, and full protection beyond



Source: NERA illustration.

The challenge with this approach is to determine the threshold level at which a greater share of outperformance (and underperformance) is shared with customers, and the incentive rate. The threshold and the incentive rate both need to be set to ensure that companies at the threshold do not have blunted incentives to further reduce costs.

As a stylised example, we set out a four-tier sharing mechanism where the post-tax incentive rate declines the greater the variation in RORE. The bands are as follows (with RORE bands post-sharing):

- 100% for the deviation in RORE minus cost of equity (RORE-kE) < +/-1%: providing most high-powered incentives for small variations around Ofgem's view of efficient costs

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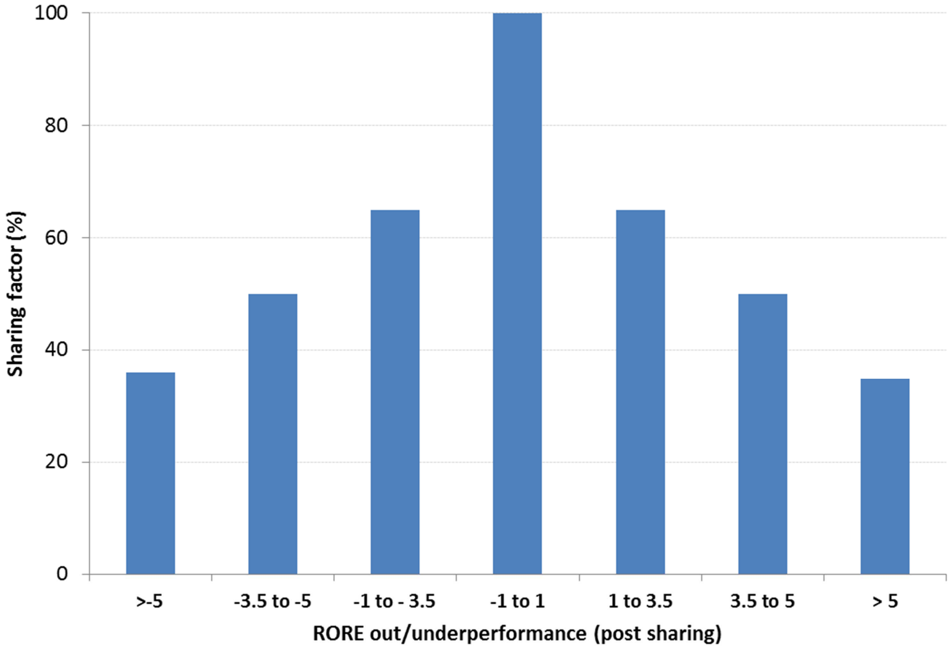
119 The Project Licence includes incentives to promote efficient expenditure by the IP during the construction period. The proposed incentive regime allows the IP to retain a fixed share of any over/underspend relative to the Base Case Forecast cost, applicable up to the agreed total level of construction costs (Threshold Outturn). Ofwat proposes a sharing factor of 40% for outturn costs above or below the Base Case Forecast, applying to cost overruns up to the Threshold Outturn. As set out in Ofwat (2015), Post-Consultation Draft Project Licence, Appendix 1 condition B.4.

120 Ofwat (2015), Post-Consultation Draft Project Licence, Appendix 1, Part A, art 11.

- 65% for RORE-kE > +/-1% and < +/-3.5%: where incentive rate is broadly as per GD1 and GDPRC1, to ensure that current incentive properties are preserved for the higher/lower performers (i.e. those outside narrow central band)
- 50% for RORE-kE > +/-3.5% and < +/-5%, and then
- 35% for RORE-kE > +/-5%: both to ensure under or over-performance shared with customers where deviations are greater. There is a risk that incentive properties of regime lost if lower incentive rate adopted.

We note that sculpting would need to apply over price control, as opposed to year-on-year basis (given annual performance varies because of capex timing), and could apply to variation in RORE related to both totex performance and outputs and customer service performance.

Figure 5.6
A stylised example of totex and incentive sculptured incentive mechanism



Finally, we consider the requirement for sculpting (as with other changes to the existing regime), depends on other decision taken by Ofgem. For example, it may not be necessary to sculpt incentive rates where Ofgem adopts a shorter price control period.

5.4.3. Ofgem's other options would not be consistent with Ofgem's RIIO objectives[121]

5.4.3.1. Option 1: Hard cap/ floor would blunt incentives

Under option 1, Ofgem proposes to introduce a hard cap or floor to restrict returns falling below or rising above pre-determined points. Although it notes that this would achieve its policy objective, it also acknowledges that such an approach could greatly diminish incentives, particularly if the pre-determined points were narrowly defined around the baseline return.

5.4.3.2. Option 2: Discretionary adjustments increase regulatory risk, and blunt incentives

Under this option, Ofgem proposes to use discretionary adjustments within the price control itself or at the end of the review period to reduce company revenues to account for variations between forecasts and actual expenditure and output performance.

Ofgem also recognises that it would need to "*specify in advance the conditions that would need to apply before [it] could make an adjustment*", and notes that this could be at a point when returns exceed a pre-determined point and the company cannot justify that these relate to genuine efficiency.

As we set out in section 5.1, one of the principal objectives of the RIIO framework was to avoid ex post discretionary adjustments as this increases regulatory risk, and undermines incentives to improve efficiency (as there is a risk that any upside return is appropriated by the regulator). Ofgem's proposal that companies would need to provide justification that higher returns were efficient is also impracticable: disaggregating returns into genuine efficiency and good luck is not straightforward given the complexity of price controls and network businesses.

5.4.3.3. Option 3: Constraining totex and output incentives based on sculpting may be reasonable; setting relative targets is not

Under this option, Ofgem identifies sculpting incentive rates for totex and output incentives, separately. Under this option, Ofgem also raises the prospect of setting output incentives based on relative performance (which it refers to as "zero sum incentives") such that the net cost to consumers is zero or a fixed incentive pot which would be distributed to networks according to relative performance.

We do not consider that these approaches are consistent with good incentive design which requires that variations in output performance are based on customers' or wider societies' valuation of the incremental improvement or decrement around the baseline, as explained in the RIIO handbook.[122] By fixing the incentive pot and making rewards or penalties relative,

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[121] Ofgem (March 2018) op cit., pp.103-106

[122] Ofgem (2010) RIIO Handbook, chapter, e.g. para 9.21. Link: https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbookpdf

companies will not know the expected reward (or penalty cost) associated with any incremental improvement (or decrement), which implies that companies will not necessarily deliver the optimal level of customer service and outputs. For example, companies may hold back on delivering service quality or output improvements beyond baseline levels where the reward is uncertain.

5.4.3.4. Option 4: RORE sharing factor may also be reasonable

Under this option, Ofgem proposes to extend the sculptured incentive rates to both totex and incentives, and thereby removes the need for separate arrangements as per Option 3. For example, Ofgem notes that a company would ensure an increasing proportion of outperformance as returns increase beyond the baseline allowance, and would pass-through an increasing proportion where the return fell below the baseline.

Ofgem also proposes that it could link the RORE sharing factor to the quality of the business plan. We note that the Information Quality Incentive (IQI) mechanism links the quality of the plan (or least the proximity of companies' cost estimates to Ofgem's view) to the sharing factor at previous reviews.

As we explain in section 5.4.2, we consider that sculpting the incentive rate could be reasonable, assuming that the marginal incentive rate was sufficiently high not to blunt incentives for cost and output improvements. As noted by Ofgem, if there is a substantive reduction in the incentive rate companies may have an incentive to delay making improvements to subsequent review periods.

5.4.3.5. Option 5: Anchoring returns would increase risk, and is impracticable

Ofgem has raised possibility of "anchoring" returns around the allowed cost of equity. The proposal involves ex-post review and adjustment to allowed revenues such that returns to the sector as a whole are no greater than the ex-ante cost of capital.

We do not consider that the approach consistent with core RIIO objective to promote cost efficiency, notably by avoiding ex-post adjustments. We also consider that the approach is not compatible with Ofgem's duty to have regard to the need to secure that licence holders are able to finance their activities.[123] It may be difficult for companies to raise debt finance or raise financing efficiently given the uncertainty over company performance, which will only be known at the end of the review period, and once Ofgem has reviewed (and adjusted) each individual companies' performance. We provide an example in section 5.4.4 of a ratings downgrade following a similar unexpected change to the regulatory regime, in this instance in Norway.

There is also a material risk that an efficient company may also not recover its costs, including a reasonable return on capital, e.g. where other companies outperform because of a preferable price control settlement or good luck. The implication is that each individual company would need to have the right to appeal other companies' price controls to ensure

[123] Section 3A of Electricity Act 89

that no company has a preferable price control settlement to its own, which is not practicable.[124] There is greater obligation on Ofgem to set revenue allowances that accurately reflect companies' costs; but paradoxically there is less incentive for the regulator to do so, as ex post the industry will only recover actual costs on average.

The approach would also undermine companies' collaborating, e.g. through day-to-day operational arrangements, as well as research, as individual company's return would depend on how well others performed.

5.4.4. Overall, Ofgem's options could threaten regulatory credibility and undermine credit ratings

Most of Ofgem's proposed options (and notably anchoring) depart from established regulatory practice and therefore undermine the predictability and certainty of the regulatory regime. This could have knock-on effects on credit metrics and cost of debt finance. For example, Moody's ratings criteria include "*stability and predictability of regulatory regime*". Moody's elaborates this measure as follows: "*We consider the characteristics of the regulatory environment in which a network operates. These include how developed and transparent the regulatory framework is; the regulator's track record for predictability and stability in terms of decision making [...].*"[125]

A pertinent example is a 2013 decision by the Norwegian Ministry of Petroleum and Energy (MPE) to impose a ceiling on off-shore pipelines ("Gassled") returns equal to the cost of capital, whereas prior to the decision the framework was based on a standard price-cap regime.[126] In the wider investor community, this represented an unprecedented change in the regulatory regime, which had up until then been perceived to be stable and predictable. It was for this reason that independent credit agencies Moody's and Standard & Poor's (S&P) took the decision to downgrade the bond issue ratings for Gassled owners. Specifically, after the MPE's consultation memo of 15 January 2013 became known, S&P lowered its rating of Njord's bonds from A- to BBB+, citing that this was "*due to the continuing lack of transparency in the process launched by the Norwegian Ministry of petroleum & Energy (MPE), and the impact this has on our view of the future stability and predictability of the regulatory regime.*"[127] After MPE's final decision was adopted, the rating for Njord's bonds was further downgraded to BB. In a ratings letter, S&P stated that the downgrade reflected a number of credit weaknesses, one of which was "*Exposure to a regulatory regime that has recently demonstrated a relative lack of transparency and volatility in its decision-making.*"[128]

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[124] For example, companies will not have access to information to fully understand and potentially appeal other companies' decisions, as companies would need to understand both the companies' plan in detail (which are not published in their entirety), and Ofgem determination and other relevant correspondence, again, not all of which is necessarily publicly available. The process of scrutinising other plans would also impose a material resource cost on companies.

[125] Moody's (2009), "Rating Methodology. Regulated Electric and Gas Networks", August, p.9. Link: https://www.eru.cz/documents/10540/462856/Priloha_c_4_RWE.pdf/a86f43c1-990c-4748-b383-1bc8abeccc59

[126] For a discussion of the case, see: Borgarting Court of Appeal (2017), EN, 30th June

[127] Dow Jones Newswires (2013), "S&P lowers Njord Gas Infrastructure ratings to BBB+; on watch negative", 2nd May.

[128] Borgarting Court of Appeal (2017), EN, 30th June, p.132.

The implication is that unexpected changes to regulatory regimes can lead to lower sub-ratings for qualitative metrics, as is the case in Norway, resulting in a lower overall credit rating for any given set of financial metrics, and worsening companies' ability to finance their activities.

5.4.5. Conclusions on potential remedies

We consider there is merit in taking measures to remove from energy networks input price inflation risk, given that this could be a material source of out (and under) performance and is outside their control. The feasibility of this approach depends on the availability of reliable and reputable indices that accurately track GDNs' costs; however, at GD1, Ofgem identified a number of indices that it considered were reflective of industry's costs.

Sculptured incentive rates and shorter price controls may also help militate against windfall gains and losses, but need to be well-designed not to diminish incentives for improvements in efficiency.

In general, it is critical that any changes to the regime do not undermine incentives for cost performance inherent in RIIO, as there is strong evidence to suggest that the ex-ante incentive arrangements have served consumers well.[129] We consider that Ofgem's options 1 (hard cap/floor), option 2 (discretionary adjustments), aspects of option 3, and option 5 (anchoring returns) are neither necessary to ensure fair returns, nor desirable from a customer interest perspective given the likelihood that they will increase risk, and/or blunt incentives to improve cost and output performance. The need for such mechanisms is also entirely unnecessary given the other potential regulatory changes, such as a shorter price control, and sculpting incentives.

5.4.6. Greater incentives for measures that matter to customers

Using data from the two most recent price controls in gas distribution (GDPCR1 and GDNs' forecast performance for RIIO-GD1), electricity transmission (TPCR4 and TSOs' forecast performance for RIIO-T1) and electricity distribution (DPCR4 and DPCR5), we have assessed whether the GDN framework incentivises companies to deliver on those customer service and environmental outputs that matter most to customers.

In Figure 5.7, we show the RoRE from incentive schemes from each company over the previous two price controls.

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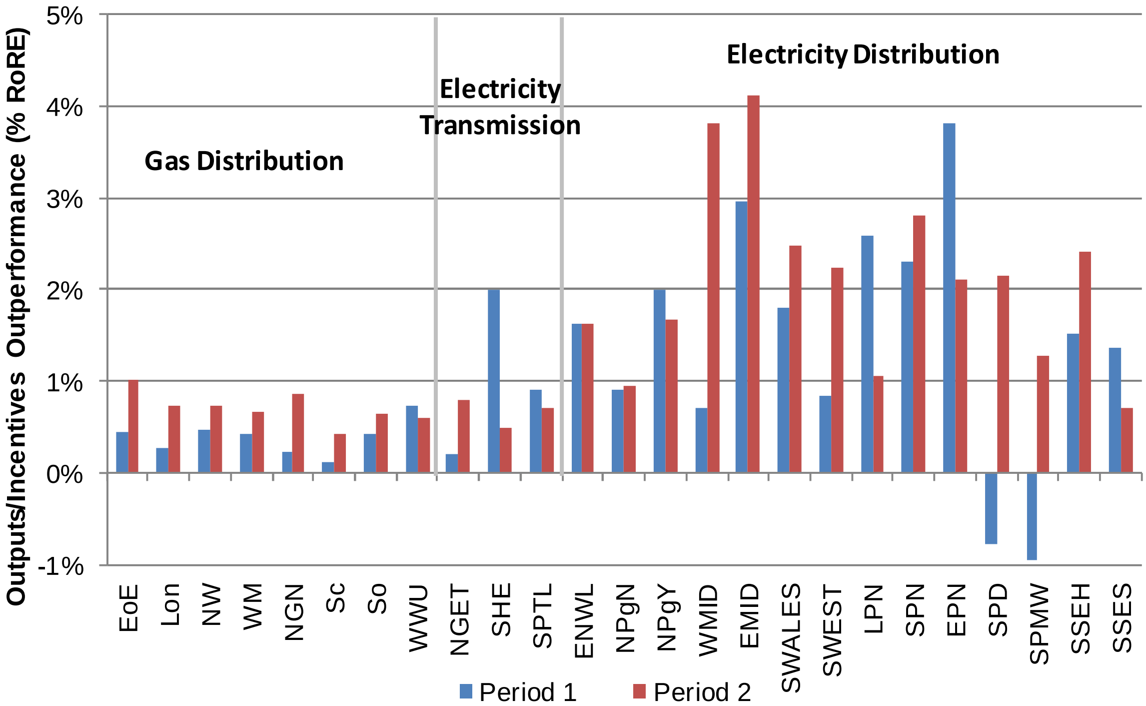
[129] For example, Ofwat has acknowledged the benefits of RIIO like framework at PR14. "*The move to totex is anticipated to open up scope for one-off improvements in cost efficiency. By providing companies with a totex target, they will be able to optimise across capital and operating expenditure.*" Ofwat (2014) Setting price controls for 2015-20 – risk and reward guidance, p. 44. Link: https://www.ofwat.gov.uk/wp-content/uploads/2015/11/gud_tec20140127riskreward.pdf

Figure 5.7
RoRE from Incentive Outperformance



Source: Regulators' and networks' reports

Whilst GDNs' expected RoRE from incentive schemes in RIIO-GD1 exceeds that from GDPCR1 for all GDNs except WWU, it is still modest compared to the large return DNOs earned in DPCR4 and DPCR5.[130]

Each industry has bespoke incentive schemes, so DNOs' outperformance on certain schemes (such as the Interruptions Incentive Scheme) may not be relevant to GDNs' potential outperformance at RIIO-GD2. However, the large outperformance seen in electricity distribution (and to a lesser extent in electricity transmission) suggests there is scope to place greater emphasis on output incentives at GD2. Similarly, in the water sector, Ofwat has applied an aggregate cap and collar on output outperformance of 2 per cent of RoRE[131], which is twice as wide a range as experienced by any of the GDNs at RIIO-GD1. Indeed, Ofwat has recently decided to remove aggregate cap and collar of +/-2 per cent of RORE as per PR14 with an indicative RoRE guidance in relation to outputs of +/-1 to +/- 3 per cent,

[130] DPCR5 performance was largely driven by outperformance on the Interruptions Incentive Scheme. The data does not allow us to identify the source of outperformance in DPCR4.

[131] Ofwat (December 2014): *Setting price controls for 2015-20 – Final price control determination notice: policy chapter A2 – Outcomes*, page 89

increasing the number of customer measures, and proportion of customer measures with financial rewards.[132]

5.4.6.1. In terms of financial measures, RORE may be less well-understood by stakeholders than ROCE (or return on RAV)

Ofgem uses RORE as its only measure of company profitability – the RORE is the return on regulated equity, and is compared to the allowed return on equity. However, return on equity is not the principal measures used by competition authorities in considering profitability for the energy sector, and may not be the most helpful measure in communicating with customers. The main disadvantage with RORE is that ignores the returns to debtholders, and notably network company performance against the cost of debt allowance.

For example, the CMA used return on capital employed (ROCE) as a principal profitability measure in the GB energy market investigation. The CMA determines the ROCE using operating profits and net operating capital employed, which is then compared to the financing benchmark, pre-tax WACC.[133]

Likewise, we consider that Ofgem should develop an analogous ROCE measure (or return on RAV) for network companies. The return on RAV which would comprise as the return element, the baseline *cost of capital* plus performance on the range of incentives used in the RORE analysis, which would be presented as percentage return on the RAV.[134]

5.5. Conclusions on ensuring fair returns

As set out in this chapter, the variation and level of returns for the GDNs and wider set of energy networks is not unreasonable or unexpected relative to the variation in the regulated water sector, the closest comparator. The variation and level of returns is also modest relative to the returns observed in comparable partially-regulated sectors such as telecoms and transport.

GDNs cost performance can be explained by both improvements in cost efficiency relative to assumptions at review, as well as the consequence of the risks, notably input price risks,

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132 Ofwat (December 2017) *Delivering Water 2020: Our final methodology for the 2019 price review*, p.42. Link: https://064f1d25f5a6fb0868ac-0df48efcb31bcf2ed0366d316cab9ab8.ssl.cf3.rackcdn.com/wp-content/uploads/2017/12/Final-methodology-1.pdf

133 Source: CMA (2016): Energy Market Investigation, Final Report, Appendix 9.9, Approach to profitability and financial analysis, para 23-25. Link: https://assets.publishing.service.gov.uk/media/576bcc14e5274a0da9000080/appendix-9-9-approach-to-profitability-fr.pdf
CC (2013): Guidelines for market investigations: Their role, procedures, assessment and remedies, Appendix A, para 9 – 16. Link:
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/284390/cc3_revised.pdf
CMA (2016) Appendix 4.2, Generation return on capital employed, para 31-88. Link:
https://assets.publishing.service.gov.uk/media/576bca9d40f0b66bda0000a4/appendix-4-2-generation-return-on-capital-employed-fr.pdf

134 There may be some differences with competition authorities' standard ROCE measure, such as calculating the network ROCE on a post-tax basis, to avoid the complication of outperformance on tax, rather than the more common pre-tax basis.

borne by GDNs during the review period. Our analysis shows that a material element of GDNs' cost performance is explained by input price risks. The weak economic recovery, and fall in commodity prices, has led to input price growth below those assumptions made at review.

Any changes to the RIIO framework should focus on rebalancing the risks borne by GDNs relative to customers, whilst preserving the incentive properties of the RIIO framework to ensure continued strong performance on cost efficiency. There are three areas that Ofgem could consider in terms of rebalancing risk, and mitigating the scope for future out (and under) performance in relation to market risks. These are RPE indexation; changes to the incentive rate; and, a shorter price control.

We consider that RPE indexation could address legitimacy concerns raised at RIIO-1 whilst preserving the strong incentive properties of the RIIO framework, although the feasibility of this approach depends on the availability of reliable and reputable indices that accurately track energy network costs.

The RIIO-2 framework should focus on those measures that customers care about. Our comparison of the scope for rewards and penalties relative to other sectors shows that the incentive framework is modest relative to other sectors and should be enhanced at RIIO-2.

Overall, the RIIO framework has worked well in incentivising companies to minimise costs, which are ultimately passed through to customers. By removing market risk and enhancing output incentives, performance more clearly aligned with company cost and output performance.

6. Assessment of SGN Relative Risk

In the section, we set out empirical estimates for beta risk for regulated GB and European networks. We also consider SGN specific risks, notably in relation to asset stranding.

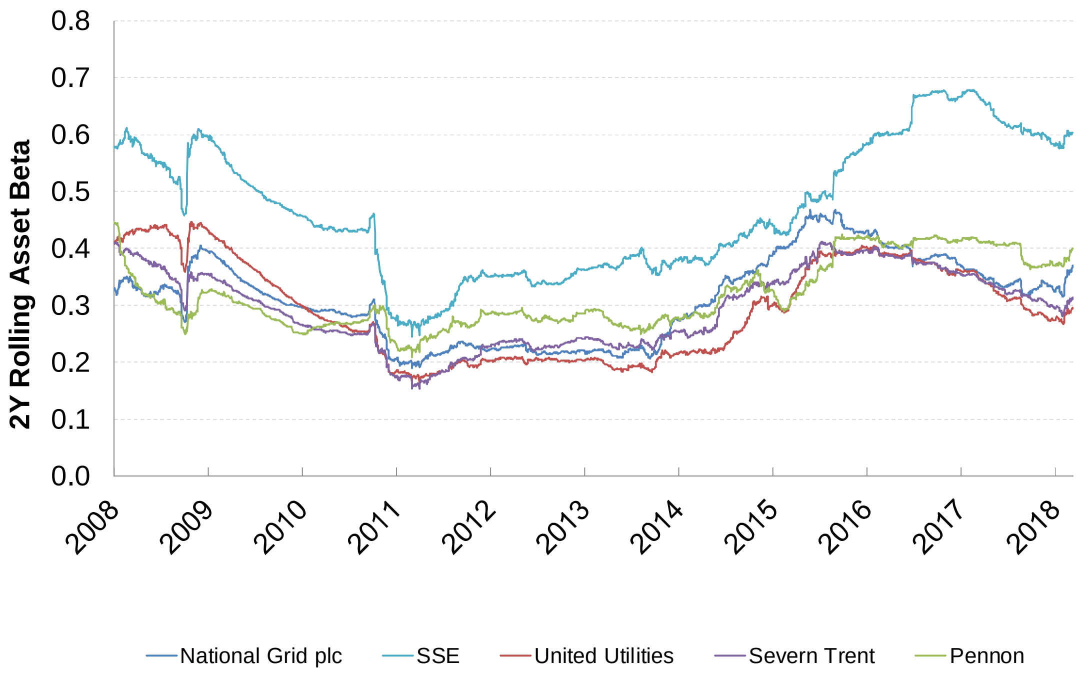
This section is structured as follows:

- Section 6.1 sets out the empirical analysis on network betas
- Section 6.2 discusses asset stranding and operational risks faced by SGN
- Section 6.3 provides evidence on empirical beta estimates for European networks, and a relative risk assessment
- Section 6.4 draws conclusions

6.1. Asset beta values have increased since GD1

Figure 6.1 shows the evolution of asset betas for NG plc and four listed UK networks comparators – SSE, UU, Severn Trent and Pennon – over the past 10 years. The asset betas for NG plc and the comparators have increased considerably since the height of the financial crisis in Europe (2011-2012), and the RIIO-1 determination in 2013.

Figure 6.1
2Y rolling asset betas for UK utilities have increased since RIIO-1, as a consequence of UK emerging from the financial crisis



Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: FTSE All Share.

Table 6.1 shows the latest empirical asset betas for UK networks, using 1-year, 2-year, 5-year, and 10-year estimation windows. This evidence shows that in the most part the asset beta estimates lie in the range of 0.3 to 0.4, with the exception of SSE's beta which is higher, reflecting its significant share of generation and supply activities, which are more risky. National Grid's asset beta is at the top-end of the range, excluding SSE. [135]

Table 6.1
With the exception of SSE, most network asset beta lies in the range of 0.3 to 0.4 with National Grid at the top end of the range

	1Y	2Y	5Y	10Y
National Grid	0.54	0.37	0.39	0.32
SSE	0.44	0.60	0.57	0.45
United Utilities	0.35	0.30	0.33	0.27
Severn Trent	0.37	0.31	0.35	0.29
Pennon	0.44	0.40	0.38	0.31
Average	0.43	0.40	0.40	0.33
Average (excl. SSE)	**0.43**	**0.34**	**0.36**	**0.30**

Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: FTSE All Share.

6.1.1. Decomposition of NG's asset beta shows increasing correlations and relative volatility

Under the OLS estimate of the beta, the equity beta derived from market data can be decomposed into correlation of the stock return with the market, and relative volatility of the stock return to that of the market:[136]

$$\beta_{equity} = \rho_{market,stock} * \frac{\sigma_{stock}}{\sigma_{market}}$$

As with other defensive stocks, NG's asset beta fell in the aftermath of the financial crisis due to both: i) higher market volatility relative to NG, reducing the second term in the above equation, as well as ii) lower correlation, the first term – with both trends explained by NG acting as a safe-haven or defensive stock.

In general, NG's beta has been returning back to "normal" (pre-GFC) levels as the volatility in NG has increased relative to the market, and increasing correlation and the decline in asset betas at RIIO-1 has now reversed. For example, our decomposition of NG's asset beta into its constituent elements, the correlation with the market portfolio and relative volatility,

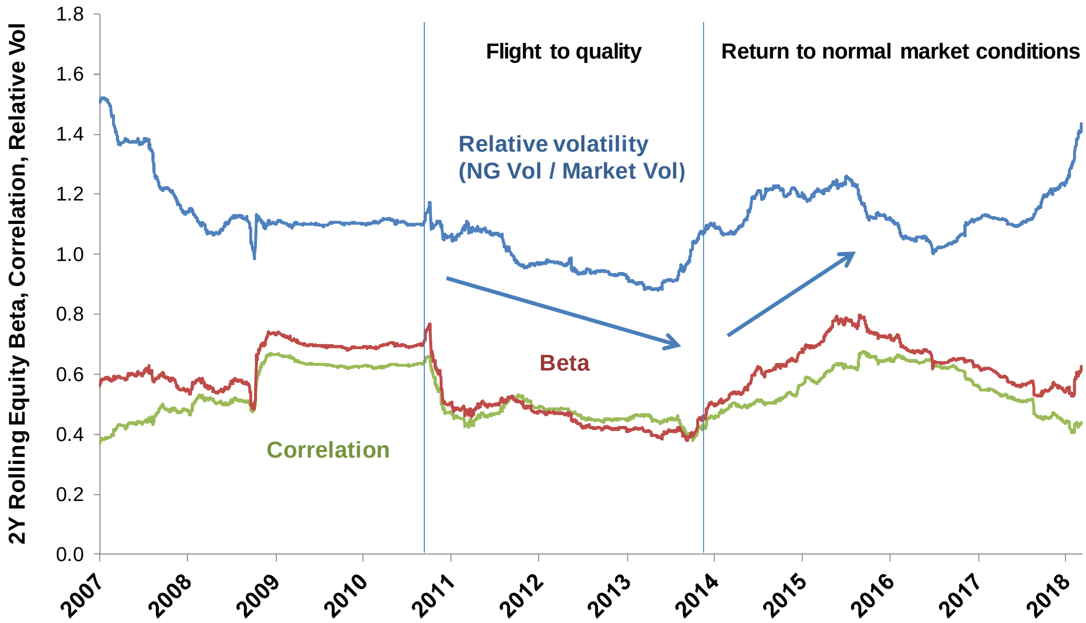
[135] Our estimates are also in line with Oxera's recent range proposed in its Report for ENA. For example, Oxera estimates a 2 year and 5 year asset beta of 0.34 and 0.38 for UK comparators (excluding SSE) based on its debt beta assumption of 0.05, equivalent to 0.32 to 0.36 based on a zero debt beta, as per our approach. The 5 year asset beta is identical to our own estimate of 0.36 (as set out in the Table); Oxera's two year asset beta of 0.32 is marginally lower than our 0.34 estimate, as we draw on the latest market evidence. See Oxera (28 February 2018), The cost of equity for RIIO-2 - Prepared for Energy Networks Association, p42-48. We use the Miller formula to solve for the implied asset beta: $\beta_{assets}=\beta_{equity}*(1-gearing)+\beta_{debt}*gearing$.

[136] The capital asset pricing model (CAPM) explains that investors are compensated for systematic risk or co-variant risk of the stock return with the market return, referred to as β risk. This is the element of risk that is non-diversifiable. In turn, β risk can be decomposed into two constituent elements: the correlation of the market return with the stock ($\rho_{market,stock}$) and the relative volatility of the stock to the market. ($\frac{\sigma_{stock}}{\sigma_{market}}$).

shows an increase in both elements since RIIO-1 supporting higher values at RIIO-2 (see Figure 6.2).[137]

The implication is that we do not consider that any weight should be placed on the asset betas over the period 2011 to 2014 because the estimates from this period are depressed by the temporary flight to quality phenomenon which has since reversed.

Figure 6.2
Increase in NG plc's beta since T1 largely explained by increase in relative volatility



Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: FTSE All Share.

6.1.2. NG Group asset beta understates GB energy network risk

We have considered how National Grid's non UK regulated businesses affect its asset beta.

In 2016/17, National Grid's UK non-regulated activities accounted for 5 per cent of the group's revenues and about 6 per cent of the group's fixed assets.[138] US regulated operations accounted for 41 per cent of the group's combined regulated asset base.[139] In order to estimate the asset beta of National Grid's UK regulated business, we have decomposed its overall asset beta into a UK asset beta and a US asset beta.

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137 We observe very similar trends for other UK listed networks.

138 These activities included UK gas metering activities; the Great Britain-France Interconnector; UK property management; a UK LNG import terminal; US LNG operations; US unregulated transmission pipelines; together with corporate activities. See National Grid Annual Report 2016/17, p.95, 96.

139 National Grid (18 May 2017), 2016/17 Full Year Results, p.14-17. This calculation only takes into account NG's remaining 39% stake in its former gas distribution business.

In the US, National Grid's operations are subject to various regulatory regimes, depending on the state in which they operate and the business activity in question. The majority of these businesses are subject to incentive regulation (about 90 per cent of regulated assets), albeit a lower-powered incentive regime than the UK. However, around 8 per cent of assets are subject to rate of return regulation, which exposes the company to less risk in terms of potential over or underperformance. In addition, National Grid Generation, which comprises around 3 per cent of the business' regulated assets, operates under a long-term power supply agreement with the Long Island Power Authority, with very low systematic risk.[140]

Overall, US regulatory regimes are determined with reference to case law which has been tested in the courts. The nature of the proceedings offers greater investor security relative to the more subjective approach, and weaker appeals mechanisms, associated with GB price controls. For example, the rate cases have enshrined principles in relation to the protection of property rights, and notions of prudency standards in relation to permissible costs.[141]

6.1.2.1. Empirical asset beta evidence for US networks are lower than for NG Group

In order to obtain a measure of the systematic riskiness of National Grid's UK regulated business, we decompose its group asset beta into a UK and US asset beta, based on the equation below.

$$\beta_{National\ Grid} = \frac{Regulated\ assets\ in\ UK}{Total\ regulated\ assets} * \beta_{UK} + \frac{Regulated\ assets\ in\ US}{Total\ regulated\ assets} * \beta_{US}$$

$$\beta_{National\ Grid} = 59\% * \beta_{UK} + 41\% * \beta_{US}$$

In order to estimate the beta associated with National Grid's US regulated businesses (β_{US}), we have identified a preliminary sample of 22 network comparators in the US.[142] We selected these comparators based on networks operating exclusively in the US, and principally engaged in regulated energy network, retail, or generation activities, as well as ensuring that the stocks met standard liquidity thresholds.[143]

Of this initial set of comparators, 3 comparators operate in the same states, and hence similar regulatory regimes, as National Grid. In particular, Consolidated Edison operates in New

140 See National Grid US Databook for 2016/17, pp. 7&8.

141 The regulation of utilities in North America faces a special kind of constraint that most other nations do not exhibit. Particularly in the United States, major regulatory statutes do not become settled methods of government control over private businesses until they are tested in the courts. There are established principles in relation to property rights, and prudency standards. See for example: NERA (2015) Half a century of estimating the cost of capital, Link: http://www.nera.com/content/dam/nera/publications/2015/PUB_Cost_of_Capital_1115.pdf

142 Bloomberg, CEG (2013), Information on equity beta from US companies.

143 We look at bid-ask spreads as a proxy for the liquidity of the listing. We consider stocks with bid-ask spreads above 1 per cent to meet liquidity threshold, based on UK and European regulatory approaches. See for example, NERA (2016) Update of the Equity Beta and Asset Beta for BT, A report for Ofcom. Section A4, pp 58-59. Link: https://www.ofcom.org.uk/__data/assets/pdf_file/0028/97039/annex_31.pdf

York (where National Grid USA has about 56 per cent of its regulated assets), and Unitil Corp and Eversource Energy have significant operations in Massachusetts, New Hampshire (and Maine), where about 30 per cent of National Grid USA's regulated assets are located.

Table 6.2 summarises their asset betas over different estimation windows. The average two-year asset beta is 0.23, and all asset betas are below National Grid's group two-year beta of 0.37.

Table 6.2
US comparators operating in same/similar states as National Grid have an average 2Y asset beta of 0.23

	1Y	2Y	5Y	10Y	% regulated	States
National Grid Plc	0.54	0.37	0.39	0.32	>95%	New York, Massachusetts, New Hampshire, Vermont, Maine, Rhode Island
Consolidated Edison	0.17	0.13	0.21	0.26	87%	New York
Eversource Energy	0.22	0.20	0.31	0.33	82%	Connecticut, Massachusetts, New Hampshire
Unitil Corp	0.28	0.35	0.34	0.18	99%	New Hampshire, Massachusetts, Maine
Average of comparators	**0.22**	**0.23**	**0.29**	**0.26**	**89%**	

Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: S&P500.

6.1.2.2. We derive a higher NG UK asset beta of between 0.43 and 0.47

Using the average asset beta of these three comparators as a proxy of the systematic riskiness of National Grid's operations in the US, and drawing on the equation above, we calculate an implied UK asset beta of 0.47 based on a two-year estimation window, and 0.46 based on a five-year estimation window (see Table 6.3 below). Our estimate is considerably higher than the composite National Grid asset beta of 0.37 (two –year beta), and approximately mid-point of the empirical betas of UK water companies and SSE (see Table 6.1).

Table 6.3
We estimate NG's UK beta of 0.46/0.47 based on three most direct comparators operating in same/similar states

	NG overall	US	UK
Share of regulated assets		41%	59%
2Y beta	0.37	0.23	**0.47**
5Y beta	0.39	0.29	**0.46**

Source: Bloomberg, NERA analysis.

To check the sensitivity of our results to the three main comparators, we also present asset betas for the full sample of 22 comparators. We obtain very similar results for the two-year betas, which are in the range of 0.13 to 0.38, with an average of 0.26. This average is considerably lower than National Grid's two-year asset beta of 0.37.

Using the full sample, we obtain an implied asset betas for National Grid's UK operations of 0.45 (2Y) and 0.43 (5Y), only marginally lower than the betas we obtained using the most relevant comparators only.

Table 6.4
Solving for NG UK beta – full set of comparators

	NG overall	US	UK
Share of regulated assets		41%	59%
2Y beta	0.37	0.26	**0.45**
5Y beta	0.39	0.34	**0.43**

Source: Bloomberg, NERA analysis.

The asset beta for UK energy networks at RIIO-2 should lie above the overall National Grid asset beta, with an implied value of between 0.43 to 0.47 based on decomposing the National Grid composite beta into UK and US operations.

6.2. Energy networks face greater risks than other networks

In this section, we describe the asset stranding risks faced by GDNs which distinguishes it from other networks, notably water networks. We also discuss operational leverage risks.

6.2.1. Greater exposure to stranding risk

In the coming years government policy towards the heat sector could materially affect the role of gas distribution (and transmission networks) in the UK. In particular, the future role for gas distribution networks will depend a wide range of factors, including the overall level of emissions target set for the heat sector (if any), the extent to which this target is expected to be achieved by reductions in gas demand by consumers currently using gas to heat homes, and the range of policy interventions put in place to achieve them.

The long-term effects of decarbonisation policy on GDNs are uncertain. In an extreme downside, GDNs might see very marked declines in throughput and user numbers or even their networks becoming redundant. In a number of other (more) credible scenarios, demand for gas will not shrink this rapidly, or may even grow slightly compared to its current levels such as through conversion to biogas or hydrogen.

In this section we set out ow European regulators have compensated investors for greater stranding risks through uplifts to the asset beta, or to the overall cost of equity.

6.2.1.1. European regulators have allowed for an uplift of 0.06 on asset betas for stranding risk

In France, Finland and Sweden, regulators apply a higher beta for gas networks compared to electricity networks, recognising higher risks faced by gas networks. For example in France, the regulator set a higher asset beta for gas transmission operators (0.45) compared to the electricity transmission operators (0.37), taking into account the uncertainty about the long-term prospects for gas.[144] As summarised in Table 6.5, regulators on average allow for an asset beta uplift of around 0.06 for gas networks relative to electricity networks.

Some other European regulators compensate for gas network stranding risk not via a beta uplift but by allowing for a premium added on top of the CAPM-based cost of equity (see Table 6.5). For example in Austria, the regulator sets a higher cost of equity (a 3.5 per cent premium on top of CAPM) for gas transmission than electricity because of the additional capacity risk borne by gas TSOs. The regulator also allows gas TSOs additional remuneration for new investments if promoters can justify the elevated risks of these projects.[145]

Table 6.5
Regulators have allowed for beta uplifts or accelerated depreciation to account for stranding risk

Regulator	Year	Type and size of uplifts	Reason for including uplifts
France	2016	Higher asset beta for gas transport (0.45), as compared to 0.37 for electricity, implying a beta uplift of **0.08**	Uncertainty about the long-term perspective for gas.
Sweden	2014/15	1) Higher beta compared to electricity transmission (0.45 versus 0.39), implying a beta uplift of **0.06** 2) Additional cost of equity premium of 1.5 per cent for gas transmission	1) Higher customer substitution risk; 2) Political and regulatory risk, high demand risk (small number of clients) and high supply risk (depend on one Danish pipeline).
Finland	2015	1) Higher beta compared to electricity transmission (0.45 versus 0.40), implying a beta uplift of **0.05** 2) Additional cost of equity premium of 1.7 per cent for gas transmission (and 1.3 per cent for gas distribution).	Higher capacity risk due to dependence on Russia as sole supplier of gas.
Austria	2017	Cost of equity premium of 3.5 per cent for gas transmission	For taking on the marketing risk of network capacities for which there is no demand.

Source*:* **France***: CRE (2016), Délibération de la Commission de régulation de l'énergie du 17 novembre 2016 portant projet de décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et de TIGF, p57; CRE (2016), Délibération de la Commission de régulation de l'énergie du 17 novembre 2016 portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans le domaine de tension HTB, p55 ;* **Sweden**: *Swedish Energy Markets Inspectorate, Kalkylranta vid berakning av intaktsram for*

[144] CRE (2016), Délibération de la Commission de régulation de l'énergie du 17 novembre 2016 portant projet de décision sur le tarif d'utilisation des réseaux de transport de gaz naturel de GRTgaz et de TIGF, p57; CRE (2016), Délibération de la Commission de régulation de l'énergie du 17 novembre 2016 portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans le domaine de tension HTB, p55.

[145] E-Control (2017), Methodology pursuant to section 82 Gaswirtschaftsgesetz (Natural Gas Act, GWG) 2011 for transmission systems of Austrian Gas Transmission System Operators, p. 6,7; E-Control (2014), Methodology and criteria for evaluating investments in electricity and gas infrastructure projects, p.6.

naturgasforetagen avseende tillsynsperioden 2015-2018, p3,4, 17-19, https://www.ei.se/en/for-energiforetag/naturgas/Naturgasnat-och-natprisreglering/Intaktsramar-2015-2018/swedegas-ab-transmission/; EY and Swedish Energy Markets Inspectorate (2015), WACC för elnätföretag för tillsynsperioden 2016-2019, p3,4, https://www.ei.se/en/for-energiforetag/el/Elnat-och-natprisreglering/forhandsreglering-av-elnatstariffer-ar-2016-20191/dokument-elnatsreglering/?p=2; **Finland***:* ***Electricity*** *- Finish Energy Market Authority (2015),Valvontamenetelmät neljännellä 1.1.2016- 31.12.2019 ja viiden-nellä 1.1.2020 –31.12.2023 valvontajaksolla - Sähkön kantaverkkotoiminta, p48,49, https://www.energiavirasto.fi/documents/10191/0/Liite_2_Valvontamenetelm%C3%A4t_S%C3%A4hk%C3%B6nkanta.pdf/9b9f5e5f-3b7a-4f9f-b461-27318cdca5db;* ***Gas*** *- Finish Energy Market Authority (2015), Valvontamenetelmät kolmannella1.1.2016 –31.12.2019 ja neljän-nellä 1.1.2020 –31.12.2023 -Valvontajaksolla Maakaasun siirtoverkkotoiminta, p48,49, https://www.energiavirasto.fi/documents/10191/0/Liite_2_Valvontamenetelm%C3%A4t_Maakaasunsiirto_final_261115.pdf/c9aea1ca-7e2a-4d6e-9c76-4592827729f1;* **Austria**: *E-Control (2017), Methodology pursuant to section 82 Gaswirtschaftsgesetz (Natural Gas Act, GWG) 2011 for transmission systems of Austrian Gas Transmission System Operators, p. 6,7; E-Control (2014), Methodology and criteria for evaluating investments in electricity and gas infrastructure projects, p.6.*

6.2.2. SGN has greater exposure to operational leverage

As well as stranding risks, SGN faces greater exposure to operational leverage risks. In this section, we describe how the CMA has adjusted for companies' operational leverage risks at previous price control reviews.

Operating leverage is a key determinant of a businesses' beta risk. [146] Operational leverage is a measure of the cost fixity of a business, and is analogous to the impact of financial leverage on a company's beta. In the same way that higher levels of debt increase in the volatility of returns to equity, businesses with higher proportion of fixed costs face greater volatility in net cash-flows in the event of shocks.

At the Bristol Water Competition Commission appeal in 2010, the CMA (then CC) noted that operational leverage (or operational gearing) was relevant to the level of beta and allowed for an uplift to Bristol Water's beta estimate relative to the sector of around 20 per cent to reflect this risk. The CMA considered the relevant measure was the proportion of revenue that was accounted for by the return and depreciation elements of the revenue building blocks (i.e. operational cash-flow as a proportion of revenue), and noted that Bristol Water's lower share implied greater systematic risk. [147]

At the Bristol Water 2015 appeal, CMA also supported an adjustment for operational leverage. At this review, it also considered totex to RCV as well as revenue to RCV as its measure of operational gearing as well as the operating cash-flow measure adopted in its 201

146 See for example, Aswath Damodaran, Estimating beta risk, slide 70. Link: http://people.stern.nyu.edu/adamodar/pdfiles/eqnotes/discrate2.pdf

147 Competition Commission (2010) Bristol Water plc price determination, Appendix N, N36 https://assets.publishing.service.gov.uk/media/55194c7240f0b614040003d2/558_appendices.pdf. Specifically, the CMA noted that the proportion of revenue for the next five years not accounted for by projected opex and tax (that is, return and depreciation over the next five years) is 50 per cent for Bristol Water compared with 59 per cent for WaSCs. Therefore, the ratio of revenue to unexposed asset value is consequently 18 per cent (=(100/50/(100/59)–1) greater for Bristol Water than for WaSCs; and hence that the asset beta for Bristol Water is likely to be 18 per cent greater.

decision.[148] In its decision, the CMA derives the beta adjustment based on its measure of operating cash-flows to revenues consistent with its approach in 2010.[149] The CMA concluded that Bristol Water had greater exposure to operational leverage relative to the listed UK water comparators, and determined an uplift to the observed empirical betas of 13 per cent, or between 0.03 and 0.04.[150], based on the same approach as its 2010 decision.[151]

Our analysis shows that SGN faces greater operational leverage risk relative to most other regulated networks, based on the CMA measure, which implies greater beta risk that should be recognised at RIIO-2.[152]

6.3. European network betas support asset beta of around 0.4

In this section, we consider empirical evidence for European energy networks' beta risk. We also compare the relative risk of the respective regulatory regimes to the GB regime.

Figure 6.3 presents the two-year asset betas of listed European comparators (i.e. Italian and Spanish transmission and distribution networks) over the past 10 years.[153] As with the UK listed networks, asset betas for these networks have generally increased since the financial crisis.

[148] CMA (2015) Bristol Water plc price determination, Appendix 10, (1) 26 https://assets.publishing.service.gov.uk/media/5627997640f0b60368000001/Appendices_5.1_-_11.1_and_glossary.pdf

[149] CMA (2015) Bristol Water plc price determination, Appendix 10, (1) 33, para. 136 https://assets.publishing.service.gov.uk/media/5627997640f0b60368000001/Appendices_5.1_-_11.1_and_glossary.pdf

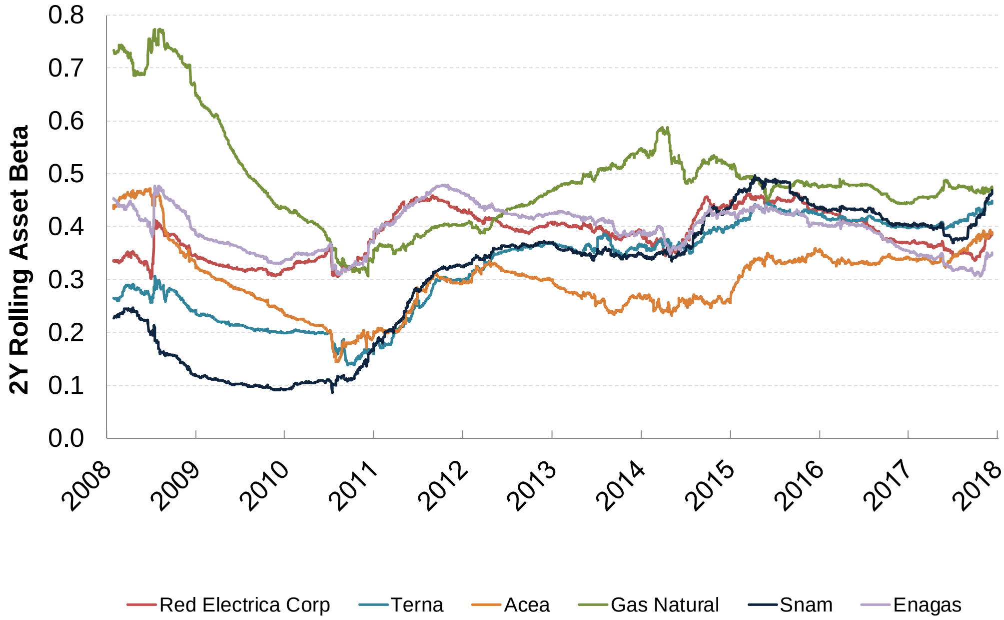
[150] CMA (2015) Bristol Water plc price determination, Appendix 10, (1) 33, pp. 325-328. Link: https://assets.publishing.service.gov.uk/media/56279924ed915d194b000001/Bristol_Water_plc_final_determination.pdf

[151] See footnote **Error! Bookmark not defined.**.

[152] Based on the CMA measure of operational leverage (see footnote 147) For SGN, we calculate and operational risk measure of around 44 per cent over GD1 implying greater risk than for other GB energy and water networks.

[153] There are other listed European network companies (e.g. Elia, Fluxys), but their stocks have generally been illiquid and are hence not included in this analysis.

Figure 6.3
2Y rolling asset betas for European utilities have increased since the crisis



Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: Eurostoxx.

The Table below provides the most recent beta estimates for these comparators, for a range of estimation windows. This evidence supports an asset beta of around 0.4 over the most recent 2 year period.

Table 6.6
Empirical beta estimates for listed European utilities[154]

	Country	1Y	2Y	5Y
Snam (GT)	Italy	0.56	0.47	0.42
Terna (ET)	Italy	0.54	0.45	0.41
Acea (ED)	Italy	0.56	0.39	0.32
Enagas (GT)	Spain	0.46	0.35	0.38
Red Electrica (ET)	Spain	0.54	0.39	0.40
Gas Natural (GD)	Spain	0.46	0.47	0.47
Average		**0.52**	**0.42**	**0.40**

Source: Bloomberg, NERA analysis, cut-off: 9 March 2018, daily data, reference index: Eurostoxx.

6.3.1. Risk assessment relative to European comparators

We have also considered the relative risk of the regulatory regimes in Spain and Italy in order to interpret the asset beta evidence. We find that in general SGN faces similar risks as Italian and Spanish networks:

In Italy, networks are regulated under a hybrid of a price cap (on opex) and a rate of return regime (on capex). Due to a periodic true-up, only a very small share of opex is subject to volume risk (around 5 per cent).[155] Moreover, opex cost risk is partially mitigated through a 50 per cent sharing factor. Italian networks face very little capex risk given that capex is effectively passed through.

Whereas the Italian networks face relative low risk based on volume and cost risk considerations, the regulator has announced its intention to introduce a RIIO-like incentive based framework, and extend the regulatory period from four to eight years. This will increase the systematic risk of these networks, and is likely to be reflected in the current beta estimates. Given the expected change to the regime, we consider the more recent Italian empirical beta evidence (0.39 to 0.47, 2Y, as per Table 6.6) is broadly indicative of the risk faced by SGN investors. However, the regulatory decision for the Italian TO is lower than the empirical evidence at around 0.3.

In Spain, transmission networks are regulated under revenue caps, as are GB energy networks. On the cost side, they are subject to a 50 per cent sharing factor on capex, but bear

[154] Our estimates are in line with Oxera's recent range proposed in its Report for ENA. For example, Oxera estimates a 2 year and 5 year asset beta of 0.38 and 0.42 for its set of European comparators based on a debt beta assumption of 0.05, equivalent to 0.36 to 0.40 based on a zero debt beta, as per our approach. The 5 year asset beta is identical to our own estimate of 0.40 (as set out in the Table); Oxera's two year asset beta of 0.36 is lower than our estimate of 0.42, as we draw on the latest market evidence and because of differences in the comparator set. See Oxera (28 February 2018), The cost of equity for RIIO-2 - Prepared for Energy Networks Association, p42-48. We use the Miller formula to solve for the implied asset beta: $\beta_{assets} = \beta_{equity} * (1 - gearing) + \beta_{debt} * gearing$.

[155] See for example Aeegsi, Decision 514/2013/R/gas (Tariff regulation for gas transport for RP4), Article 13.

the full cost risk on opex. Gas Natural (GD) is subject to a revenue cap, based on opex and capex volume drivers. There is no sharing of opex and capex out or underperformance which indicates that it faces greater cost risk than UK networks, although this is mitigated by annual updates to the allowance in line with volume drivers and unit costs.[156] As with the Italian regime, we consider that investors in GB energy networks bear a similar degree of risk as investors in Spanish transmission networks, and Gas Natural which have asset betas in the range of 0.35 to 0.47 (2Y), as per Table 6.6..

We have estimated asset betas for listed European networks in Italy and Spain. The empirical evidence supports an asset beta of around 0.4 over the most recent 2 year period. Our comparative risk assessment of the Italian and Spanish regimes suggests that investors face broadly similar risks as per UK energy network investors, and therefore 0.4 asset beta provides a relevant benchmark for UK energy networks.

6.4. Conclusions on relative risk

Our analysis of UK listed network companies – NG plc, United Utilities, Severn Trent, and Pennon – show that the majority of beta estimates lie in the range of 0.3 to 0.4, with values for NG plc towards the top-end of this range, e.g. NG plc’s two-year asset beta is 0.37. In general comparator listed network betas have been returning back to “normal” (pre-GFC) levels as the constituent elements of beta risk – correlation with the market and relative (absolute) risk – are trending back to normal levels.

NG plc’s composite beta understates the risk associated with NG UK networks assets, given lower risk US networks. NG plc’s composite beta reflects the combined systematic riskiness of NG plc’s UK and US operations, and empirical evidence shows that US operations are lower risk. Solving for NG plc’s implied UK beta, we obtain a range of 0.43 to 0.47 for NG plc’s UK beta.

We have estimated asset betas for listed European networks operating in Italy and Spain. The empirical evidence supports an asset beta of around 0.4 over the most recent 2 year period. Our comparative risk assessment of the Italian and Spanish regimes suggests that investors face broadly similar risks as per GB energy networks, and therefore 0.4 asset beta provides a relevant benchmark for GB energy networks.

Overall, the empirical evidence shows that GB energy networks, as shown by the decomposition of NG plc’s asset beta and European energy network betas, face higher beta risk than GB water networks.

Our qualitative risk assessment shows that SGN faces greater risks than most other networks from asset stranding risk, given the uncertainty over government policy and technological solutions to the decarbonisation of heat. Our review of European regulatory decisions indicates an uplift to the asset beta of 0.06 to compensate for such risks. SGN also faces greater exposure to operational leverage, as measured by the return and depreciation elements as a proportion of revenues, the principal measure adopted by the CMA.

156 **Gas**: Ley 18/2014, https://www.boe.es/boe/dias/2014/10/17/pdfs/BOE-A-2014-10517.pdf; **Electricity**: Ley 24/2013 (https://www.boe.es/boe/dias/2013/12/27/pdfs/BOE-A-2013-13645.pdf), Royal Decree 1047/2013 (https://www.boe.es/boe/dias/2013/12/30/pdfs/BOE-A-2013-13766.pdf) and Royal Decree 1048/2013 (https://www.boe.es/boe/dias/2013/12/30/pdfs/BOE-A-2013-13767.pdf).

Appendix A. Regulators Bespoke Cost of Debt Mechanisms

In this section, we set out examples of regulators that set the cost of embedded debt based on a notional capital structure and efficient market index, but where the framework recognises the timing or debt profile of the network company (notably, where the debt profile is atypical because of the size of the company or the size of the investment programme).

The examples we cite correspond to Ofwat's approach to TTT, Ofgem's approach for Scottish Hydro Electric Transmission (SHETL), as well as UREGNI's cost of debt indexation for NI gas distribution.

A.1. Ofwat's cost of debt for TTT reflects its atypical debt structure

For the Thames Tideway Tunnel (TTT), Ofwat developed a cost of debt mechanism where the ex-ante allowed cost of debt is adjusted over time in line with changes in market cost of debt. The adjustment provides TTT with a cost of debt allowance based on the efficient market cost of debt (measured by the BBB iBoxx index) at the time of *actual* debt issuance.[157] That is, the mechanism recognises the actual debt issuance profile over the construction and initial operational phase of the project.

In addition, in the post construction phase, Ofwat has acknowledged that it would need to consider TTT specific factors in determining the cost of debt allowance. Notably, Ofwat has proposed an alternative assumption for the embedded debt: new debt ratio (90:10) for the TTT relative to the industry average (75:25), in recognition of TTT's specific debt issuance schedule. Ofwat also recognises that the cost of TTT's embedded debt could be different to the industry as a whole, and "*it is likely that such factors will be taken into account in arriving at the overall cost of debt*".[158]

A.2. Ofgem's cost of debt allowance for SHETL reflects its specific circumstances as a relatively small TO

For the gas distribution (RIIO-GD1), and gas and electricity transmission (RIIO-T1) price controls, Ofgem adopted a cost of debt indexation based on 10-year trailing average of benchmark index yield for most network companies. However, for Scottish Hydro Electric Transmission's (SHETL), Ofgem developed a bespoke cost of debt index with a weighting based on the company's investment profile (proxied by change in RAV).

In its decision, Ofgem stated that the expected atypical investment and debt profile as the reason to adopt a bespoke approach: "*we acknowledged that a simple trailing average index may not fully reflect the cost of debt of a company with a rapidly-growing RAV if interest rates change sharply*."[159]

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157 Ofwat (September 2014), Draft license for the Infrastructure Provider of Thames Tideway Tunnel, p. 65, para. 6.7

158 Ibid, p.18

159 Ofgem (February 2012), RIIO T1: Initial Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd, para. 5.44

A.3. UREGNI recognises debt profile of NI gas distribution networks

UREGNI has established a cost of debt indexation mechanism which recognises the benchmark cost of debt at the time of actual issuance for both Phoenix Natural Gas (PNG) and Firmus Energy (FE), gas distribution networks in Northern Ireland.

Specifically, UREGNI proposes to set a cost of debt allowance based on the benchmark value in the month corresponding to the networks' debt issuance. UREGNI's approach recognises the concentrated and lumpy financing requirements for these two entities.[160] PNG's circumstance is particularly analogous to that of PW: with PNG having a single public bond given its small size relative to the minimum efficient scale to access public bond markets.

[160] UR (September 2016) Final Determinations, Annex 14 http://www.uregni.gov.uk/uploads/publications/Annex_14_-_Rate_of_Return_Adjustment_Mechanism.pdf

Report qualifications/assumptions and limiting conditions

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