RIIO-3 Sector-Specific Methodology Consultation – Finance Annex

NGN Response

6 March 2024

Overview

We welcome the opportunity to respond to Ofgem's SSMC Finance Annex. The approach to regulatory finance is of course fundamentally important, as it always is for network price controls. The context for RIIO-3, however, presents some particularly important challenges. It is essential that Ofgem recognises these challenges and addresses them, including by interpreting the UKRN guidance as it was intended, to provide a fair risk-return balance for investors and an attractive, investable proposition.

Before responding to each FQ in detail, we first summarise what we see as some of the key high-level issues for RIIO-3. Throughout this response, we make reference to a number of external consultancy reports which have been commissioned by the networks to inform our response to the SSMC on finance topics.

The following reports were commissioned by the Energy Networks Association (ENA):

- Oxera (February 2024). "RIIO-3 Cost of Equity"
- Frontier Economics (March 2024). "Equity Investability in RIIO-3"
- Frontier Economics (March 2024). "The Low Beta Puzzle"
- NERA (22 February 2024). "Additional Cost of Borrowing for the RIIO-3 Price Control"
- Frontier Economics (March 2024). "Initial consideration of break-even inflation for price control purposes"

The following reports were commissioned by the Gas Distribution Networks (GDNs) to further investigate sector-specific issues:

- Oxera (March 2024). "Risks and investability of the GB gas distribution sector"
- KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)
- KPMG (March 2024). "Credit Rating Agencies' perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond" (confidential)
- NERA (March 2024). "Impact of GDNs' Reduced Debt Tenor on Additional Cost of Borrowing at RIIO-3"

In this response, we offer an NGN-specific perspective where appropriate and aim to avoid unnecessary duplication with the consultant reports. For the avoidance of doubt, if we do not mention or expand on any particular point made in the consultant reports (or the ENA

we are
the network

submission to which NGN has been a party), this should not be interpreted as NGN's disagreement with its validity or significance.

We note that this response is submitted at a point when a substantial number of uncertainties remain, including as regards some of the key policy and methodological decisions that have yet to be made by Ofgem. Further, financial markets have been highly volatile in recent times and new evidence will continue to emerge. We, therefore, see this submission as the start of a period of ongoing consultation and detailed evidence building that is required to ensure an investable price control is set for RIIO-3, with the key staging posts of the RIIO-3 Business plan submission in December 2024 and draft and final determinations in 2025. We would welcome Ofgem's confirmation that it is open to considering the evidence we may be able to submit beyond the 6th March 2024 deadline, as part of ongoing engagement post-SSMC.

We welcome the addition of an 'investability' concept - this is just as important for the gas sector as it is for the electricity sector

Ofgem's recognition of 'Investability' as a distinct notion is new for RIIO-3 and we welcome Ofgem's plan to develop it "*to better understand whether the allowed return on equity is sufficient to retain and attract the equity capital that the sector requires*".[1]

We note, however, that Ofgem appears to focus its new investability concept on the ET sector only, for example stating that: "*Through the next ET price control and beyond, we expect network companies will need to seek 'fresh' equity from their investors over and above what they would be able to fund via retained earnings, and at a time where there is greater competition for investment and capital in the UK water and global regulated infrastructure sectors.*"[2] In contrast, Ofgem states "*The challenges for the gas sector are different",* focusing on falling gas demand and the need to support the transition to a carbon-free economy.[3]

Investability is relevant and equally important for GDNs. It is far from certain that the GD sector is in a state of terminal decline - there are many plausible scenarios in which the gas grid has a long-term future that is critical for UK customers. In any case, the sector must continue to invest during RIIO-3 to keep the networks safe and resilient for their expected ongoing use over the coming decades. BAU spend (including mandatory Repex) is still significant and likely to rise in the medium term due to legislative workload requirements and to support the Net Zero transition.

We agree with Oxera who *"consider the concept of investability to be as important for gas networks as for electricity networks, because it is needed to ensure network resilience and orderly transition to a decarbonised economy. This is not least because investor perception of*

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[1] Ofgem (2023). RIIO-3 Sector Specific Methodology for the Gas Distribution, Gas Transmission and Electricity Transmission Sectors, Finance Annex (RIIO-3 SSMC Finance Annex), paras 1.6, 5.9

[2] RIIO-3 SSMC Finance Annex, para 1.6

[3] RIIO-3 SSMC Finance Annex, para 1.7

Ofgem's actions is transferrable among different energy assets that it regulates and may regulate in the future (e.g. CCUS, hydrogen and new nuclear) and because the gas sector needs to continue being competitive in its requirements for capital."[4] Frontier Economics also discussed heightened risk at RIIO-3[5] and concluded that the concept of investability must apply equally across all networks, both electricity and gas.[6]

The strategic importance of gas networks has been highlighted by the government in its recent draft strategy and policy statement: *"The continued resilience of necessary infrastructure remains a key priority in order to maintain our safe, efficient and reliable gas networks"*[7].

Further, Ofgem's Net Zero duty and imminent Growth duty mean GDNs must be incentivised to continue to invest in order to further enhance service performance, be resilient, ready for any pathway to Net Zero and provide capacity for growing industries (including hydrogen, especially in hard-to-decarbonise end-use sectors).

Investability is therefore as important for GDNs as it is for ET and Ofgem should apply the concept to all network sectors in RIIO-3.

In addition, we agree with Ofgem that a price control should be considered investable if the allowed rates of return are sufficient to both attract and retain equity capital.[8] As Frontier Economics explains in detail[9], both elements of this are critical – noting for example that: *"As a matter of principle, if a certain level of cost of equity is required to attract new equity investment, then this is also the rate that is required to retain existing equity. There is no easy way to partition business risk between new and old equity…. all equity investors bear and share the same set of risks, regardless of the time when their investment was made."* [10] Ofgem's allowed return on equity must therefore apply to all equity. Frontier also explain that: *"It would be irrational and wrong to try to set differential rates of return on equity, under the pretence that new investors require higher returns while existing investors do not"*[11] - a point which Ofgem already recognised in its Future Systems and Network Regulation decision.[12]

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4 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.58-59.

5 Frontier Economics (March 2024), "Equity Investability in RIIO-3", Section 2.2

6 Frontier Economics (March 2024), "Equity Investability in RIIO-3", para 5.

7 DESNZ (February 2024), 'Draft Strategy and Policy Statement for Energy Policy in Great Britain', p. 17. https://assets.publishing.service.gov.uk/media/65d4b31738fef9001ab5b0ae/draft-strategy-policy-statement-energy.pdf

8 RIIO-3 SSMC Finance Annex, para 1.6, 3.1, 5.9

9 Frontier Economics (March 2024), "Equity Investability in RIIO-3", paras 2-5, Section 1.2.3, Section 3.2.

10 Frontier Economics (March 2024), "Equity Investability in RIIO-3", para 105

11 Frontier Economics (March 2024), "Equity Investability in RIIO-3", Section 3.2

12 Ofgem (October 2023), Future Systems and Network Regulation Decision, Core Document, para. 6.23

In the case of gas networks, the allowed returns must reflect both the baseline risks and financial market realities, as well as the asymmetric stranding risks we face (discussed further below). If allowed returns do not sufficiently capture this, then the risk for customers is that essential investments in system resilience, asset health, and improvements in efficiency/innovation are rationed. Ensuring ongoing network resilience, which is the cornerstone of what we provide to our customers, requires an investable proposition which drives the required ongoing investment through management and shareholder incentives.

For these reasons, and as expanded on by Frontier Economics, we consider that investability applies equally to all equity investments, both existing and new. The need to retain equity investment should not be downplayed.

The macro-economic environment has significantly changed since RIIO-2

The final determination for RIIO-GD2 was published in the context of a prolonged period of extremely accommodative monetary policy since the Global Financial Crisis (GFC). The Bank of England base rate had been below 1% (and close to zero) for upwards of ten years, and market expectations at the time were that the base rate would remain low for several years ahead.[13] Yields on Index-Linked Gilts were extremely low following a prolonged decline (see Figure 1 below). Frontier Economics' report[14] explains how regulator's determinations of the cost of equity – and in particular the Total Market Return (TMR) parameter – had been conditioned on what was referred to as the 'era of cheap money' following the GFC. Frontier's chart illustrating this is copied below.

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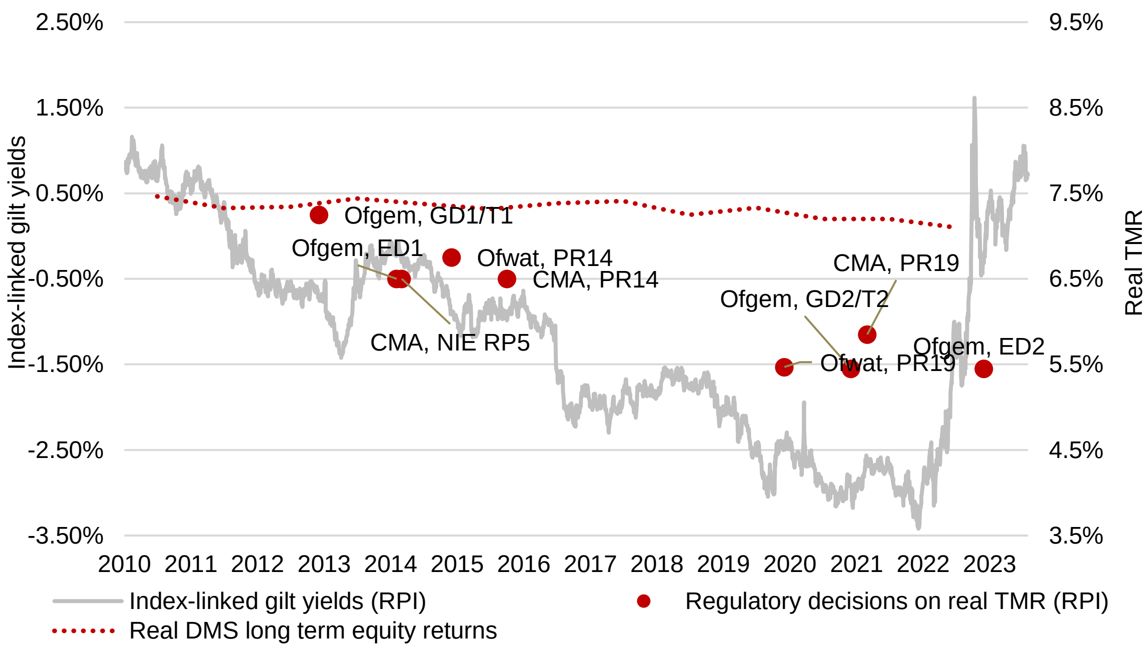
13 See, for example, Table 1.A and Chart 2.6 in the BoE Monetary Policy Report November 2020 here: https://www.bankofengland.co.uk/-/media/boe/files/monetary-policy-report/2020/november/monetary-policy-report-nov-2020.pdf. The MPC stated "Market-implied paths for policy rates in advanced economies have been broadly unchanged since the August Report, suggesting policy rates will remain at very low levels for several years."

14 Frontier Economics (March 2024), "Equity Investability in RIIO-3", Section 2.1.1

Figure 1. Long-run TMR as estimated by DMS, Regulatory decisions on TMR and yields on 20-year ILGs



Source: Frontier Economics (March 2024), "Equity Investability in RIIO-3"

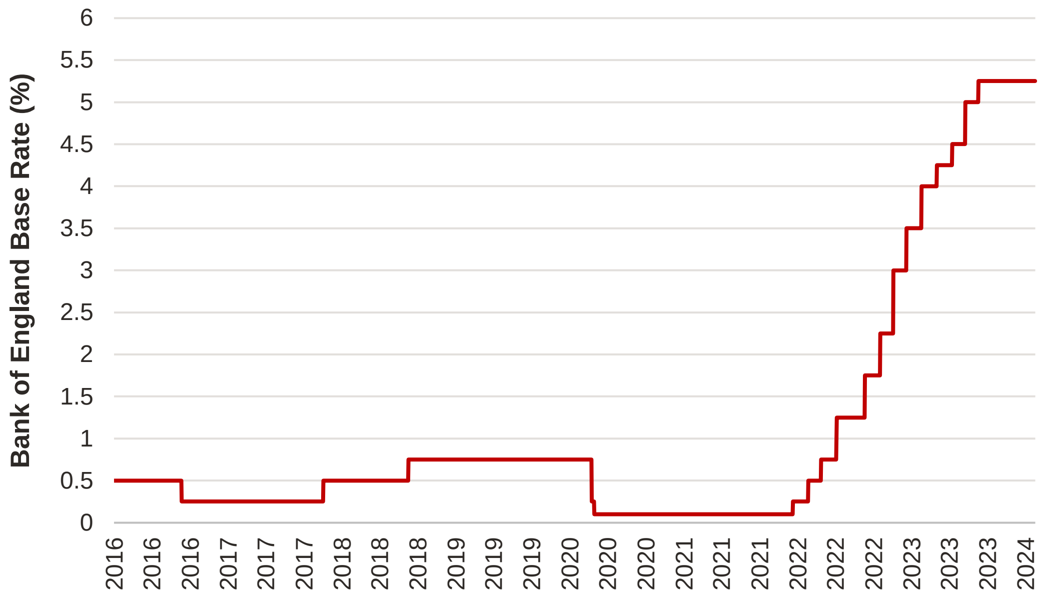
The dotted red line in the chart (right-hand scale) shows the underlying evidence on real long-term equity returns as published by DMS, using the methodology and data which was standardly used by regulators prior to the GFC to estimate TMR. The estimated long-run level has fluctuated in a narrow range roughly between 7.1% and 7.3% (in real terms according to DMS's definition of inflation for the UK), i.e. it has barely changed. But regulatory decisions on real TMR have nevertheless drifted downwards, following the trend in ILG yields. Indeed, as Frontier explains[15], regulators have been clear in the past that they were lowering TMR because of their perception of wider market evidence, in particular interest rates.

Since the RIIO-2 final determination, however, the interest rate environment has abruptly changed, in response to major global shocks. ILG yields have risen steeply (see chart above), returning to levels last observed prior to the GFC. The Bank of England base rate rose sharply,

[15] Frontier Economics (March 2024), "Equity Investability in RIIO-3", Section 2.1.1 paras 59 - 64

from 0.25% at the start of 2022 to 5.25% today (see Figure 2). There is no indication that a return to the period of ultra-loose monetary policy is remotely likely.[16]

Figure 2. Bank of England base rate



Source: Bank of England

Ofgem has to acknowledge this new reality in its SSMD and recognise that it needs to reflect carefully on what this means for its allowed cost of equity and cost of debt, if RIIO-3 is to deliver an overall investable and financeable price control consistent with Ofgem's statutory duty. We expand on this further below.

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[16] See, for example, Table 1.A and Chart 2.6 in the BoE Monetary Policy Report February 2024 here https://www.bankofengland.co.uk/-/media/boe/files/monetary-policy-report/2024/february/monetary-policy-report-february-2024.pdf

Market evidence shows that rolling forward Ofgem's RIIO-2 Cost of Equity approach will be insufficient even for a 'baseline' return for a notional energy network

Ofgem has indicated that it will continue to use CAPM as the primary tool when estimating the cost of equity and that it will look to the UKRN guidance – which substantially aligns with Ofgem's RIIO-2 approach – as the starting point for RIIO-3.

Given the fundamental shift in macroeconomic conditions since the RIIO-GD2/T2 Final Determination, it is important that the CAPM approach is carefully calibrated to ensure the investability of the sector over the next price control. Risk-free rate indexation alone will not be sufficient given that companies need to be able to attract and retain the desired blend of financing for their investment programmes. There is a risk that the wedge between the allowed cost of debt and the allowed cost of equity shrinks to the point where it becomes irrational for an investor to be willing to make and/or retain an equity investment.

Continuing with Ofgem's RIIO-2 CAPM approach will result in a cost of equity that is insufficient even for an average energy network. Oxera calculates that a simple roll forward of Ofgem's RIIO-GD2/T2 approach would result in a cost of equity range of 4.75% - 5.77% (CPIH-real, at 60% gearing) with a midpoint of 5.26%. This is 71bps higher than the CoE estimate in the RIIO-GD&T2 final determination, where the CoE allowance at 60% gearing was 4.55%. The increase is driven by an increase in the RFR from -1.58% to 1.32%.[17]

Oxera's estimate of a CAPM-based CoE range for RIIO-3 is 5.08–6.48% (CPIH-real, at 60% gearing), with a mid-point of 5.78%.[18] This is higher than Oxera's estimate of a RIIO-2 'roll forward' range (i.e. 4.75% - 5.77%) due to differences in the RFR and the TMR. Moreover, Oxera's method does not account for the impacts of sector-specific forward-looking risks, which have increased materially since RIIO-2 and which we turn to in the next sub-section.

Wider market evidence confirms that a simple roll-forward of RIIO-2 would give a range for the 'baseline' CoE that would be too low (all figures below on a CPIH-real basis).

- Oxera's ARP-DRP framework suggests that the appropriate point estimate of the CoE needs to be above the top end of the Ofgem rolled-forward range from RIIO-2 (i.e. 5.77%), and in fact closer to the upper end of the Oxera range (i.e. 6.48%).[19]

Frontier Economics' report[20] also shows that:

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[17] Oxera (February 2024). "RIIO-3 Cost of Equity", page 11.

[18] Oxera (February 2024). "RIIO-3 Cost of Equity", page 74.

[19] Oxera (February 2024). "RIIO-3 Cost of Equity", page 13.

[20] Frontier Economics (March 2024), "Equity Investability in RIIO-3", Figure 1 and Section 4-6.

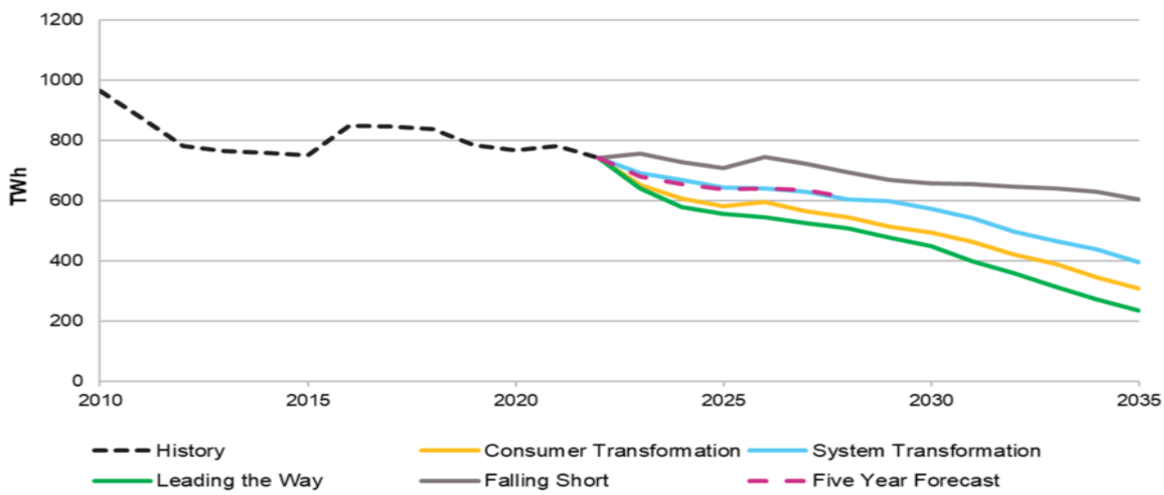
- Evidence from hybrid bonds indicates a point estimate for the cost of equity of 6.7%, within a range of 5.8% - 8.5%;
- Further cross-check evidence from long-term profitability benchmarks suggests a range of 5.9% - 8.4%;
- Updating two equity-based cross-checks that were used by Ofgem at RIIO-2 for the latest information[21], the result also falls within the range indicated by the other Frontier-preferred cross-checks above.

Given this cross-check evidence, it is clear that Ofgem – when properly interpreting the UKRN guidance – will need (based on today's evidence) to increase the cost of equity allowance relative to a simple roll-forward of the RIIO-2 methodology, in order for RIIO-3 to be a financeable and an investable proposition.

In addition, there is increasing risk to gas sector investors due to asset-stranding risk

We agree with Ofgem's acknowledgement of a very challenging macro environment for the gas sector in RIIO-3. Fundamentally this is driven by material long-term scenario uncertainty surrounding demand for gas. Ofgem's chart – replicated in Figure 3 below - shows historical gas demand and the latest FES 2023 forecasts. Under the *Leading the Way* scenario gas demand is forecast to fall sharply to ~200TWh in 2035. But under the *Falling short* scenario, the reduction is much less dramatic (to ~ 600TWh). Net Zero pathway uncertainty therefore varies by a factor of c.3x in just 11 years from now.

Figure 3. Historical and FES 2023 forecast gas demand



Source: Ofgem (2023), RIIO-3 SSMC Overview Document – Figure 1

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21 The two Ofgem cross-checks that have been updated are (1) the investment manager forecasts of TMR cross-check (and associated CAPM with investment managers' TMR), which Frontier has supplemented with evidence from the Fernandez TMR survey; and (2) the infrastructure fund implied equity IRR cross-check.

These risks in Gas Distribution have increased since RIIO-2 as a result of a number of significant developments.

- The Net Zero imperative was enshrined in Law in June 2019[22] - i.e. during the RIIO-2 process. While Ofgem's DD (summer 2020) and FD (December 2020) could have taken account of this, much of the direction of travel for RIIO-2 was already set during the earlier consultation phases (RIIO-2 SSMD was published in May 2019). More importantly, substantially more analysis has now gone into the implications of the binding Net Zero target for all sectors of the economy, relative to when the RIIO-2 decision was made. And, of course, we are now 5 years closer to the 2050 Net Zero target date.
- The Energy Act of 2023 established a formal Net Zero Duty for Ofgem only in October last year as well as introducing a raft of other developments aiming to drive rapid change in the Energy Transition.[23]

These developments all substantially reinforce and enhance the expectations of meeting the Net Zero target relative to RIIO-2. However, major uncertainty remains in what the implications of this are for gas demand and the gas distribution sector, as indicated by the range of FES scenarios shown above.

- In its second National Infrastructure Assessment, published in October, the National Infrastructure Commission concluded that *"there is no public policy case for hydrogen to be used to heat individual buildings. It should be ruled out as an option to enable an exclusive focus on switching to electrified heat."*[24] FES scenarios such as Customer Transformation and Leading the Way show a very dramatic reduction in the use of gas (whether natural gas or hydrogen) amongst the bulk of our direct customer base in the next two decades.
- On the other hand, it is clear that heat pump uptake is slow (and far behind the target of 600,000 installations per year). In addition, recent developments in offshore wind and nuclear call into question the deliverability of high electrification scenarios.
- Substantial policy uncertainty prevails – for example, given the delays in bans on gas boiler installation in new homes and sales of new internal combustion engine cars; and changes being considered for the clean heat market mechanism (recently branded as a "boiler tax"). DESNZ's Hydrogen for Domestic Heat decision is not due until 2026.

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[22] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law

[23] https://www.ofgem.gov.uk/publications/ofgem-welcomes-energy-act-getting-royal-assent

[24] https://nic.org.uk/studies-reports/national-infrastructure-assessment/second-nia/#tab-foreword

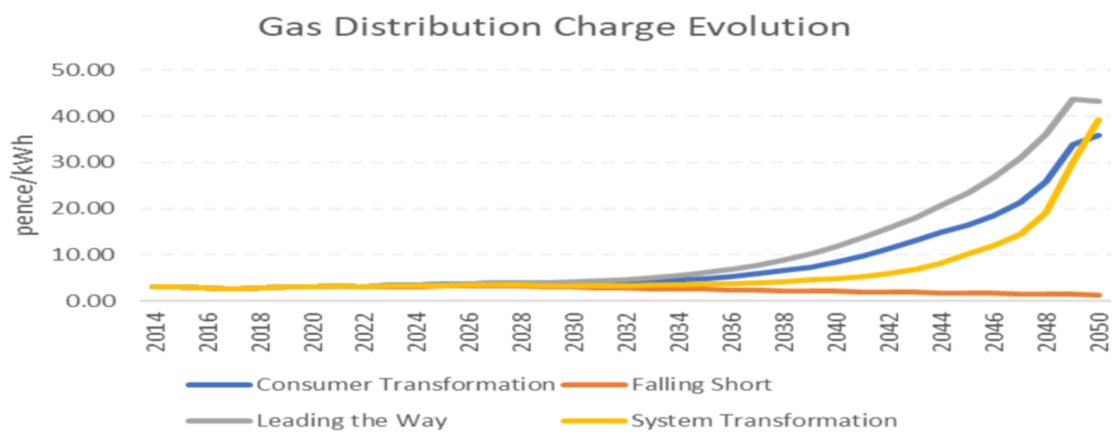
Despite this uncertainty, there has been a clear trend in the annually updated FES scenarios over the past few years. The table below compares total forecast (from 2025 - 2050) gas volumes in the latest FES 2023 update vs. the FES published in 2020, across each scenario.[25] It is clear that the FES scenarios have become materially more pessimistic over time about the aggregate gas demand remaining in these scenarios.[26]

Table 1. Gas volumes evolution (FES 2020 vs FES 2023)

Scenario	***Total gas volumes 2025-2050 (FES 2023) GWh***	***Total gas volumes 2025-2050 (FES 2020) GWh***	***% Difference***
ST	7,277,626	8,570,335	-15%
CT	5,703,151	7,290,497	-22%
LW	5,105,999	6,568,904	-22%

As Ofgem's SSMC correctly identifies, some FES scenarios could result in unpalatable increases in domestic customer bills in the long-term (Figure 4).

Figure 4. Ofgem's GD Consumer Charge Estimate under Status Quo Depreciation Policy



Source: RIIO-3 SSMC Finance Annex, Figure 4.

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25 We note that Falling Short was only introduced from FES 2022 and we therefore exclude it from the table. We note, however, that in FES 2022 the Falling Short gas volume amounted to 12,785,290 GWh, i.e. the FES 2023 also reduced gas volumes in FS vs FES 2022 (by c. 1%).

26 For FES 2023: Total gas volumes = "Total GB Gas Demand (Excluding exports and shrinkage)" less ("Total gas demand (gas NTS connected only) for electricity generation" and "Hydrogen Production - Natural Gas Demand"). The data is found in worksheet "ED3". For FES 2020: Total gas volumes have been obtained by summing "Total end-use residential gas demand", "Annual end-use gas demand from the commercial sector", "Annual end-use gas demand from industry", "LDZ connected peaking/flexible plants", "Gas end-use demand for transport". The data is found in worksheet "ED3".

We welcome Ofgem's leadership and openness to properly consider the issues caused by the wide range of demand scenarios and the need to develop an appropriate regulatory response. It is right that Ofgem has recognised the stranding risk in the gas distribution sector. It is indeed a critical issue for GDNs because the risk is borne by investors and hence has to be remunerated today.

We agree with Ofgem that, if the stranding risk is not appropriately addressed, this *"could undermine regulatory stability and predictability and is likely not in the consumer interest"*.[27] However, we are concerned that Ofgem appears to limit the *"primary ways"*[28] by which it seeks to address this risk in gas distribution to solely assessing depreciation profile and re-openers. As we explain further below, there is a need to not only mitigate but also compensate for the risks borne by debt and equity investors.

There is strong evidence that gas-specific risks are being priced into the debt market and if not addressed may negatively impact the credit quality of GDNs

GDNs have collectively commissioned KPMG to undertake Debt market analysis using the most up-to-date data[29] and to summarise Credit Rating Agencies' (CRAs) perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond[30]. KPMG's reports (for more details please refer to the full reports and our response to FQs) lead to the following key conclusions:

- The cost of debt for gas distribution has been on a clear upward trend since the start of RIIO-1 (as assessed by spreads, i.e. controlling for wider interest rate movements);
- There is clear evidence of a material and growing premium on the cost of debt for gas distribution networks relative to other network sectors, including electricity. It is likely that these trends are being driven by heightened uncertainty around gas demand evolution and other considerations like investor ESG mandates;
- Despite stranding risk not being reflected in the current credit ratings or ratio guidance (CRAs currently assume that the regulator will address the risk), it would be seriously negative for ratings and financeability if the risk does not get an appropriate regulatory response;
- CRAs are increasingly aware of the risks around possible reduction in network utilisation and consider that they are becoming more acute. According to some agencies, time is running out for the regulatory action to be an efficient mitigant against the risk of RAV stranding and hence they expect action in RIIO-3;

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27 RIIO-3 SSMC Finance Annex, paras 1.7, 8.37

28 RIIO-3 SSMC Finance Annex, para 8.14

29 KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)

30 KPMG (March 2024). "Credit Rating Agencies' perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond" (confidential)

- CRAs generally consider accelerated depreciation as a credit-supportive measure as long as it helps mitigate long-term risk; however if it becomes apparent that this measure alone is not sufficient to fully recover RAV, this could elevate concerns about stranding risk and become credit-negative;
- The agencies will monitor the developments in this area closely and if a pronounced likelihood of asset stranding in the GD sector arises, the CRAs will likely revise their target credit ratios for a given rating level and/or via reassessing business risk/regulatory framework for the sector. As a result, gas networks could be downgraded but also other adjacent sectors could suffer if the regulatory framework is no longer considered transparent, predictable and supportive;
- In terms of investability, agencies welcomed the new concept which they interpreted as warranting the ability to attract the right funding and investors, and also as a stronger alignment between the regulation and market appetite to fund the sector (both on the equity and debt side).

Ofgem should recognise in its SSMD that this latest market evidence means that a simple roll-forward of its existing (or weighted) iBoxx benchmark is likely to lead to underfunding of efficient debt costs in the gas sector and adapt its approach accordingly.

More generally, we also note that significant investment required in other RAB-regulated sectors over the next decade will also create greater competition for debt (and equity) capital. It will be important to ensure that the cost of capital allowance for RIIO-3 captures all of these shifts in market conditions.

We would also stress that the establishment of an efficient notional structure must be based on evidence and supported by actual company decisions across the relevant sectors. We do not agree with regulators using the notional financial structure (e.g. the gearing level) as a lever to arbitrarily try to improve financeability or investability metrics (see more on notional gearing in FQ11).

These risks will also affect the required cost of equity for gas distribution networks

In our view, the observed gas premium and other emerging market evidence on the cost of debt are likely to be the result of the increasing underlying perception of gas-specific risk, including stranding risk arising from the material uncertainty around the trajectory of future gas demand. If this affects debt investors, it will also affect equity investors. Oxera's report on GDN risks and investability considers this question. Oxera notes that the evidence from debt markets on gas-specific risks has clear implications for the return on equity allowance. Since gas bond spreads are higher, this must translate into higher ARP and hence a higher cost of equity: "*the evidence of a 'gas premium' in credit spreads of long-term bonds, which by extension means that the asset risk premium and therefore cost of equity of gas networks* *are likely to be higher than the baseline, which is set with reference to historical betas of UK utilities*". [31]

We note in particular that stranding risk is asymmetric. There is a non-zero probability of a material loss for investors in Gas Distribution, with no counterbalancing upside: Ofgem cannot allow revenue over-recovery but there's a non-zero chance of revenue under-recovery and asset stranding (under a number of FES scenarios). At RIIO-2, Ofgem acknowledged that Stranding Risk is asymmetric in nature: "*It did not seem to us that stranding risk is perfectly systematic, although we did see some basis for it being asymmetric*"[32]. The data since then reinforces that the risk is present, and it has already been acted upon by regulators internationally (as referenced below and expanded upon in the expert reports appended to our submission).

It is well-established that asymmetric risks of this nature cannot be directly addressed or accounted for within the CAPM framework. For example, in the RIIO-3 SSMC Ofgem alluded to a need to recognise asymmetry: "*we may need to adjust the allowed return on equity such that expected returns match our best estimate of the cost of equity*".[33]

In our view, to account for the risks that are faced and to ensure investability for the GDNs, Ofgem has to go beyond the combination of "investability" levers it has already identified (i.e. beta, equity issuance allowance, return on debt and depreciation). The UKRN guidance, which by definition assessed issues from a cross-sectoral / cross-regulator perspective, clearly did not consider whether, or how, this particular asymmetric and sector-specific risk should be addressed within the GDN sector. It is particularly important for GDN investability that Ofgem accounts for the stranding risk that we face. This stranding risk can't be captured by CAPM, nor can it be completely removed using existing regulatory mechanisms.

Oxera's report on GDN risks and investability identifies that:

- The asset stranding risk is asymmetric, albeit it is likely to have "systematic components". For example, in EU countries where direct comparison is possible (i.e. Spain, Italy) gas betas have been, on average, 0.02–0.04 higher than those of electricity networks at least since 2019.[34]
- Besides, there is clear evidence of a 'gas premium' based on credit spreads for long-term gas vs electricity bonds. A higher credit spread when there is no difference in

[31] Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.58

[32] Ofgem (December 2020). RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator. Finance annex. Para 3.76. https://www.ofgem.gov.uk/publications/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator

[33] RIIO-3 SSMC Finance Annex, para 3.88

[34] Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p. 4,6.

financial risk, implies a higher asset risk premium, and by extension a higher cost of equity.[35]

- Regulators internationally use a wide range of tools to address the asset stranding risk. Some of these measures mitigate the risk, while others compensate for it.[36]
- For example, the regulator in Austria has granted a 3.5% cost of equity uplift to compensate investors in gas networks for volume risk, which essentially has the same implications as the stranding risk. In New Zealand gas networks were allowed a 0.05 beta uplift in recognition of the asset stranding risk; and in the fibre sector, the possibility to accelerate allowed depreciation or to shorten asset lives alongside an ex-ante revenue allowance of 10bps applied to the RAB to compensate for the asymmetry of risk were provided. The regulator in France applies several tools: it has shortened asset lives, set the cost of capital allowance in nominal terms, and allowed a higher cost of equity for gas networks in the form of a higher beta, mentioning the need to compensate for the asset stranding risk as a reason for granting the uplift.[37]

Oxera explains that *"cash-flow remedies, such as accelerated depreciation and re-openers, which Ofgem is considering using to address the asset stranding risk in RIIO-GD3, are useful in mitigating the risk. However, they do not eliminate it, because uncertainty around networks' ability to recover the costs remains—for example, due to customer bills having to increase to an untenable level, especially if the user base shrinks in the future. Therefore, an uplift to the allowed return on equity relative to the 'baseline' allowance for a steady-state GB energy network would be justified"*[38]. Oxera concludes that a combination of both risk mitigation and compensation regulatory tools *"may be appropriate in the context of RIIO-3 and beyond, and a few regulators indeed use both types of measures in their regimes"* [39]. We fully support Oxera's findings.

The stranding risk can be quantified and should be accounted for. We propose a conceptual framework for quantifying a RIIO-3 cost of equity (or WACC) uplift in our response to FQ8. In simple terms, the objective of this framework is to estimate an expected (i.e. probability-adjusted) loss which could arise in a stranding scenario, and solve for a CoE (or WACC) uplift which would bring investors' expected long-term returns back in line with the underlying CAPM-CoE (or WACC). We would seek to engage further with Ofgem on developing this approach over the coming months: the framework and supporting evidence for input assumptions can and should be developed further. An alternative method is using Oxera's ARP-DRP framework.

In any case, multiple international regulatory precedents on compensating investors for the stranding risk support our view that this risk is quantifiable and its remuneration is not only

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35 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.6-7.

36 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.7.

37 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.43, 51.

38 Oxera (March 2024), "Risks and investability of the GB gas distribution sector",p.4-5.

39 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.58.

justified by economic theory but has already been provided by the regulators abroad (we expand on this in our response to FQ8). We also agree with Oxera that a cost of capital uplift *"has the advantage of being flexible: if uncertainty around the scale or the timing of the asset stranding risk is removed, the cost of capital uplift can be adjusted accordingly, or even removed, which ensures that there is no double-counting of the risk in favour of networks"*[40]

We would welcome it if Ofgem confirms its openness to engage with us to robustly quantify the required WACC uplift for stranding risk asymmetry.

Ofgem's existing framework for ensuring financial resilience is already strong and working for customers – changes are not needed and could be damaging

We consider that the measures currently in place are adequate to provide Ofgem with oversight and assurance that regulated entities are financially resilient and have sufficient resources to maintain such resilience. We agree with Ofgem that "*In the round, we consider these financial resilience measures to have been broadly effective in helping to incentivise shareholders and management to maintain financial policies and outcomes that are consistent with a financially resilient sector*"[41].

We consider that most of the "*potential shortfalls*" with the current financial resilience regime identified by Ofgem[42] are overstated in the absence of any evidence that the sector is not financially resilient or that the current measures are not sufficient or effective. In particular, any perceived issues with the existing licence conditions, should Ofgem be concerned about transparency and visibility of company-specific constraints, could be dealt with by providing further guidance or streamlining the existing processes.

Further, some of the options Ofgem is considering would introduce burdens that could affect investor appetite and cost of equity (e.g. dividend lock-up at a higher threshold than investment grade or 80% gearing; or a 12-month period for Availability of Resources Board certification). If Ofgem wishes to take these proposals further, a proper impact assessment is necessary. Ofgem should ensure that it does not impose additional costs on customers which are not justified by associated benefits.

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40 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.34.

41 RIIO-3 SSMC Finance Annex, para 6.8.

42 RIIO-3 SSMC Finance Annex, para 6.14

Response to consultation questions

Allowed return on debt

FQ1. Do stakeholders consider there to be good reasons to deviate from the overall approach set out under UKRN Recommendation 8?

UKRN Recommendation 8 is that: "*Regulators should estimate an allowance for an efficient company under the notional financial structure with actual debt costs suitably benchmarked against other market evidence*". While we broadly agree that this is applicable to an average energy network, there is clear evidence that (1) the cost of debt in the gas sector has been increasing by more than wider interest rate movements; and (2) the increase in the gas sector cost of debt has been greater than in electricity, i.e. that there is now a discernible premium for gas sector debt relative to other network sectors, including electricity. Therefore, the GD sector cost of debt allowance requires a separate consideration for the reasons discussed below.

We set out some of the key evidence from the above-mentioned KPMG reports but refer the reader to the respective reports for more detailed analysis.

First, the cost of debt in the GD sector is increasing both in public and private markets. For example, the public market trend is shown in KPMG's assessment of spreads over Government bonds (see Figure 1 in KPMG's report[43]). Spreads in secondary market trading as measured by the tenor-adjusted sector-specific iBoxx Utilities index also have been on a steady upward trajectory since 2013, increasing by more than c. 65%. KPMG observes the same trend of the rising cost of debt for new issuance in private debt markets (see Tables 1&3 in KPMG's report[44]): spreads to tenor-adjusted iBoxx Utilities index have increased by even a higher margin than in the public markets, rising by c. 165% since 2013. As KPMG shows, private debt markets have grown in importance for the GD sector (since 2017 c.£3.2bn has been issued in the GD sector in private debt markets compared to c.£4.9bn in public debt markets) and could become more important going forward, given the growing competition for debt capital. We note that by calculating spreads, KPMG's analysis effectively controls for wider movements in interest rates driven by macroeconomic shocks. More data and information on the methodology are contained in the KPMG report.

[43] KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)

[44] KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)

Second, we have observed that investors are increasingly unwilling to provide capital to the gas distribution sector with maturities which are longer than 10-15 years. NERA in its report for GDNs[45] observes that the average tenor at issuance of GDNs' bonds has reduced to around 10 years since 2020. Consistent with this, KPMG's analysis shows that tenors on newly issued debt are shortening. KPMG found that tenor at issue (for public debt) in the GD sector fell by 5.3 years from 15.4 years on average in the period 2014-2018 to 10.1 years on average in the period 2020-24. A decline was also observed in the GT sector, whereas for ED and ET, the tenor at issue increased modestly over the period analysed (such that the tenor at issue for new public debt is now lower in the GD sector than in ED, ET and water, see Table 4 in the KPMG's report[46]). As KPMG identifies, several factors may be driving this trend although it could be that gas-specific risk perceptions amongst investors, for example in relation to the evolution of gas demand, may be limiting the tenors that GDNs are able to raise debt at.

Third, KPMG's analysis of the differential between gas (GD & GT) and electricity (ED & ET) spreads shows that since 2022 there has been a persistently positive differential (i.e. gas spreads exceed electricity spreads). For G-spread, the difference in spreads used to be very modest, averaging close to zero historically. However, since 2022 gas spreads have been persistently wider than those of electricity, averaging 29 bps for A-rated bonds and 15 bps for BBB-rated bonds from 2022 to present. Since early 2023 the G-spread has widened further. The same picture manifests in terms of the differential in iBoxx utilities spreads: since 2022 spreads have been higher in gas compared with electricity (24 bps for A-rated bonds and 19 bps for BBB-rated bonds respectively)[47].

These findings are consistent with those of Oxera, who also identifies clear evidence of a gas sector premium over electricity in bond yield data in its report[48] (see charts below). This evidence shows that the market is pricing in higher risk for gas networks in the long term relative to the electricity networks, with the long-term 'gas premia' consistently being above the short-term premia and the spread increasing in the last three years.

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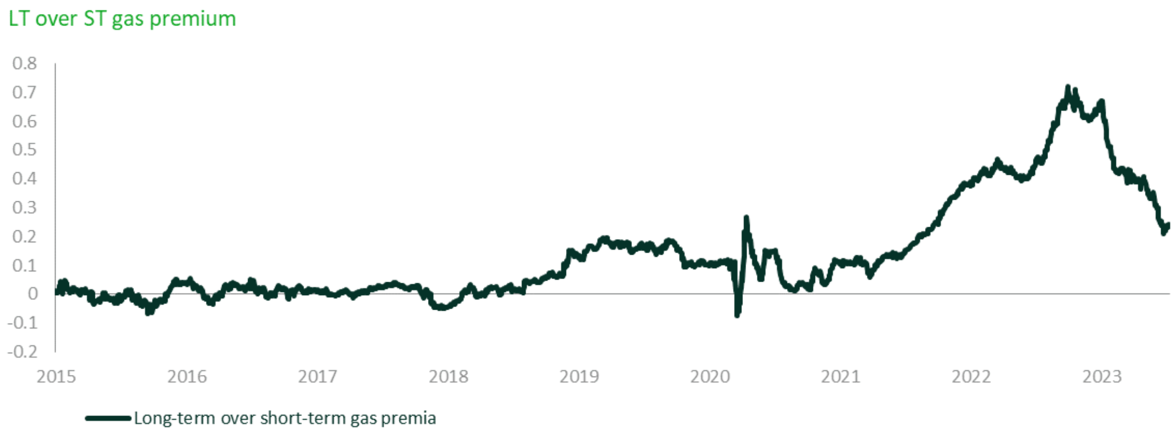
45 NERA (March 2024). "Impact of GDNs' Reduced Debt Tenor on Additional Cost of Borrowing at RIIO-3"

46 KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)

47 KPMG (March 2024). "Debt market analysis: gas distribution networks and UK-regulated comparators" (confidential)

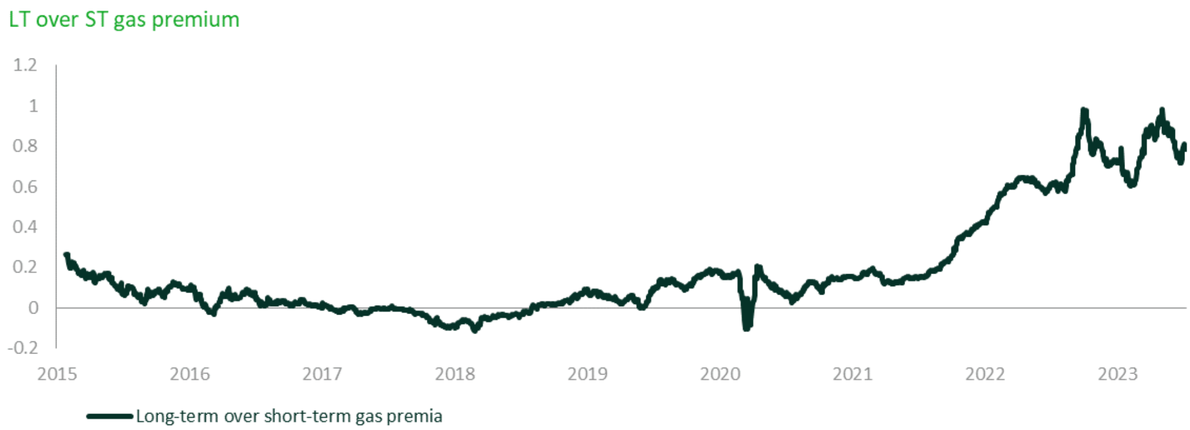
48 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.16.

Figure 5. Long-term over short-term gas risk premia, based on NGN and NGED pairs of bonds (%)



Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", Figure 2.1.

Figure 6. Long-term over short-term gas risk premia, based on SGN and NGED pairs of bonds (%)



Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", Figure 2.2

The implications of this evidence go beyond the calibration of the cost of debt in gas distribution. As Oxera points out *"The widening of the spread for long-term debt is consistent with additional asset risk for gas relative to a baseline steady-state energy network […] the evidence of the 'gas premium' on long-term debt implies that a premium is also required on the allowed return on equity for gas networks, on top of the baseline allowance"*[49]. This is

[49] Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.17-18.

supported by similar differentials in Oxera's comparison of gas and electricity betas in international jurisdictions (see FQ9 below).

Fourth, KPMG's review of relevant material from the three main Credit Rating Agencies (S&P, Moody's, and Fitch) shows that, while the agencies currently base their credit quality assessment on the expectation of regulatory support allowing for a full RAV recovery, longer-term uncertainties around gas demand evolution are well-recognised and closely monitored by all agencies. In their publications, agencies mention that the risk around possible reduction in network utilisation became more acute. Other salient points include[50]:

- All agencies state that in the longer term, a continued decline in demand for gas could create credit challenges;
- If the risk is not addressed appropriately and results in a pronounced likelihood of asset stranding for the GDNs, the CRAs would likely revisit their assessment of the business risk and tighten their target credit ratios for the sector. It is worth reminding that Moody's tightened its ratio thresholds for UK water companies as a result of its reassessment of the UK water regulatory regime[51] (thresholds in water are still approximately half a rating notch tighter than those of UK electricity and gas networks). In Moody's' case, no differentiation between electricity and gas currently applies. However, Fitch already assumes a lower GDN debt capacity, but may consider tightening it further: *"[GDNs] have a lower debt capacity compared to electricity distribution peers, reflecting lower long-term sector visibility. Fitch would consider revising the debt capacity if we believe that the energy transition would result in tougher regulatory decisions, ultimately increasing gas companies' business risk."*[52] S&P notes the precedent of revising the business risk profiles in Europe: *"Gas grids remain exposed to long-term stranded-asset risk. In 2023, we reflected this by revising to strong from excellent the business risk profiles and correspondingly tighter minimum credit metric expectations on gas grids in the Iberian peninsula. Like in Latvia, we now differentiate Iberian gas networks' long-term prospects from those of power grids"*[53];
- Agencies highlight that it will be important for credit ratings to consider how the regulatory framework would adapt to address the sector's challenges and note that regulatory support will constitute a major driver of the GDN's credit risk evolution. The actions of the regulator are considered by the CRAs as key in managing the risk of asset stranding. According to some CRAs, time is running out for the regulatory action

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50 KPMG (March 2024). "Credit Rating Agencies' perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond" (confidential)

51 Moody's (May 2018). "Regulated water utilities - UK: Regulator's proposals undermine the stability and predictability of the regime"

52 Fitch (December 2023). Rating Action Commentary; Fitch Affirms Scotland Gas and Southern Gas IDR at 'BBB'.

53 S&P (January 2024). "EMEA Utilities Europe's energy transition: Still on, despite crosscurrents"

to be an efficient mitigant against the risk of RAV stranding and hence they expect some action in RIIO-3;

- As regards the impact of accelerated RAV recovery on credit metrics, CRAs may adopt different approaches. For example, Moody's opinion was that accelerated depreciation may not lead to a revision of the business risk or leverage thresholds. While it tightened its minimum funds from operations (FFO) / net debt and net debt / fixed assets requirements for Gasunie when the regulator in the Netherlands accelerated depreciation, this was associated with removing the distorting impact of accelerated depreciation on the ratios[54][55]. S&P does not appear to make the same adjustments as Moody's in its credit metric calculations, hence viewed accelerated depreciation as a credit-supportive measure because it improves the FFO/Debt ratio (albeit it's not clear how it would view it in terms of the business risk profile). Fitch expresses an expectation that networks would need to reduce their net debt/RAV over time in order to maintain their ratings in a declining RAV scenario.

The existing evidence base cited above (which is likely to be further supplemented later in the price control process as new information emerges) makes it clear that proper consideration of an efficient, appropriately benchmarked cost of debt, as well as the financeability/investability assessment, for RIIO-3 needs to take account of gas-sector-specific market evidence. When considered holistically, the evidence presents a coherent picture that there is an investor perception that GD is exposed to different, greater risk than comparable RAB-regulated sectors, i.e. that there may be a gas-specific risk premium which is responsible for the rising cost of debt faced by GDNs in recent years and the trend of shortening tenors.

More generally, we also note that significant investment required in other RAB-regulated sectors over the next decade will also create greater competition for debt capital. It will be important to ensure that the cost of debt allowance for RIIO-3 captures all of these concurrent shifts in debt market conditions.

We would also stress that the establishment of an efficient notional structure must be based on evidence and supported by actual company decisions across the relevant sectors. We do not agree with regulators using the notional financial structure (including the gearing level and the assumed proportion of index-linked debt (ILD) as a lever to arbitrarily try to improve financeability or investability metrics (see more on notional gearing in FQ11).

FQ2. Do stakeholders have evidence in support of, or opposition to, one or more of the updated indexation or inflation remuneration methodologies under consideration?

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[54] Accelerated depreciation changes the timing of when cash flows are received, but does not add to the overall available cash flows over the (remaining) life of the asset; changes are NPV neutral; the numerator of Moody's AICR deducts regulatory depreciation (and other measures that affect timing of cash flows) from FFO and no further adjustment would be required, but metrics that only reflect FFO will likely require an adjustment.

[55] Moody's (April 2021). Moody's affirms Gasunie's A1/P-1 ratings, stable outlook

Unfortunately, we haven't been provided with sufficient detail by Ofgem, especially as regards the Cost of Debt weighting methodology and any possible transitional arrangements in terms of potential changes to inflation remuneration, to express informed views on these fundamental, but also complex and technical methodological approaches. We hope to be in a better position to do this and estimate the impact on NGN and our customers when Ofgem provides further clarity. For now, we provide our high-level observations on the two related (but still distinct) questions contained within FQ2. We discuss first the updated indexation methodology and then the inflation remuneration methodology.

Cost of debt indexation methodology

Ofgem has proposed moving to a weighted average rather than a simple average for the benchmark index. We agree that the move to a weighted trailing average has some merit in principle, in that the current unweighted average is not always well-calibrated to short-term changes in market rates. We also support Ofgem's hypothesis that it is possible that a weighted trailing average may require less ongoing regulatory intervention.

However, Ofgem has yet to provide any detail on how a number of elements related to these proposals would operate in terms of the mechanics. For example, Ofgem's current illustration[56] of how the indexation methodology might work requires a number of assumptions, such as existing RAV being refinanced annually on an even basis and the tenor of debt being equivalent for both embedded and new debt. It is also not clear when a weighting would be introduced and if so, what the cut-off date would be for what Ofgem refers to as the 'legacy RAV'.

Since Ofgem has not set out how it intends to make these assumptions, we do not consider we have sufficient information to be able to fully comment on the proposed methodology changes.

We note that in the RIIO-2 Framework Decision, Ofgem set out four main principles it proposed to use for setting the cost of debt allowance.[57] These were:

- Consumers should pay no more than an efficient cost;
- The cost of debt allowance should be a fair and reasonable estimate of the actual cost of debt likely to be incurred by a notionally geared, efficient network company;
- Network companies should be incentivised to obtain the lowest cost financing without incurring undue risk; and

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56 Ofgem, Illustrative Example CoD Weighted Trailing Average, https://www.ofgem.gov.uk/sites/default/files/2024-01/Illustrative%20example%20CoD%20weighted%20trailing%20average.xlsx

57 Ofgem, 2018, RIIO-2 Framework Decision, https://www.ofgem.gov.uk/sites/default/files/docs/2018/07/riio-2_july_decision_document_final_300718.pdf

- The calculation of the allowance should be simple and transparent while providing adequate protection for consumers.

We consider that any new methodology Ofgem might be considering should align with these principles. In addition to these, we also consider that regulatory precedent is an important aspect. It is essential to maintain a degree of consistency across price controls and predictability of the regulatory system in order to limit investors' exposure to regulatory risk and incentivise investment in the sector.

Inflation remuneration methodology

As outlined in our response to Ofgem's Call For Input (CFI)[58] regarding the impact of high inflation on the network price control operation, we do not consider there to be a conceptual issue with the current regulatory regime. The existing arrangements are functioning in line with their long-standing design principles. They have served customer interests well by attracting a substantial amount of investment in upgrading and maintaining our network at an efficient cost of capital, which enables us to fulfil regulatory outputs and deliver exceptional customer service. Changes to the inflation remuneration methodology are therefore not required.

The SSMC explains that the indexation or inflation remuneration methodologies are intended to address the situation where sharp fluctuations in outturn inflation lead to "out or underperformance potential for equity"[59]. As outlined in our response to the CFI, we disagree with Ofgem's characterisation of this as "out- or underperformance". We consider this as a transfer of value between the debt investors and the equity investors, where the customers are left unaffected.

More importantly, the mechanism of indexing RAV over time and using a real WACC is part of an overall system which is described as providing 'inflation protection' for energy networks. In our view, the system has served to attract capital at a low cost. Indexing the RAV to outturn inflation has been a fundamental component of the regulatory model since privatisation – not just for energy networks but across regulated infrastructure sectors generally. This approach has been a key underpinning of investors' understanding of the risks associated with investing in network assets. Business decisions have been taken over decades in reliance on this long-standing indexation approach. Making changes to these fundamental principles – particularly without adequate transition arrangements to enable companies to adjust portfolios – would be unprincipled and increase the perception of regulatory risk.

This is particularly true given that, for the majority of RIIO-1 outturn inflation was lower than the long-term assumption used by Ofgem, such that equity holders sustained lower real returns than would have otherwise been expected. No change in policy was considered at

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[58] https://www.ofgem.gov.uk/publications/call-input-impact-high-inflation-network-price-control-operation

[59] RIIO-3 SSMC Finance Annex, para 2.29

that point. However, Ofgem is now considering intervention following RIIO-2 where inflation has been higher following rare macroeconomic events. This is not good regulatory practice.

Furthermore, given the Bank of England and other central banks globally have responded to these shocks, we would expect the return of a more typical inflation environment. Introducing long-term significant changes to the regime in light of short-term macroeconomic shocks harms investor confidence in the sector and is not consistent with regulatory stability and predictability.

We refer back to our more comprehensive discussion of these and other points in our response to the CFI, and we also note the submissions in that response from the ENA[60] and Frontier Economics[61], which we continue to endorse.

Although we disagree with the need to introduce a change to the indexation/inflation remuneration methodology in principle, we recognise that Ofgem is considering 3 possible mechanisms:

Option 1: Nominal allowance for fixed-rate debt.

For fixed-rate debt, a nominal allowance would be used alongside de-linking the fixed-debt portion of the RAV from outturn inflation indexation.

Option 2: RAV indexation to match long-term inflation assumption.

The real cost of debt allowance would remain but split into proportions for fixed-rate debt and index-linked debt. The fixed-rate debt portion of the RAV would be indexed using long-run inflation expectations used to deflate the cost of debt allowance (prevailing 5^{th-}year CPIH OBR forecast at each index reading[62]) instead of outturn inflation. The same approach (the current approach) would apply to index-linked debt.

Option 3: Review of inflation assumption.

This would maintain the current real cost of debt allowance but consider alternative long-term inflation assumptions, as opposed to the OBR's five-year forecast (typically 2%). Ofgem notes that current approaches under consideration include relying on breakeven inflation, using a wedge for RPI/CPI differences until 2030, or using a forward measure of breakeven inflation.

Notwithstanding our view that none of these changes are necessary or in the best interest of customers – we provide some observations on these three options below.

60 Energy Networks Association (September 2023). Response to Ofgem's Call For Input - Impact of high inflation on the network price control operation.

61 Frontier Economics (September 2023). Comment on Ofgem's Call for Input on the Effect of High Inflation. A report prepared for the Energy Networks Association.

62 RIIO-3 SSMC Finance Annex, p. 19

- **Option 1** represents a very significant departure from the existing regime and to our knowledge would be an entirely novel regulatory approach, unused by any other regulator in the UK. This is likely to prove detrimental to the stability and predictability of the regulatory process and hence impact the cost of capital. As noted in our CFI response, in Northern Ireland the Utility Regulator introduced a novel methodology (which also related to inflation treatment in the cost of debt allowance) which prompted Moody's to conclude that Phoenix Natural Gas's "*credit quality was constrained by a deterioration in the stability and predictability of the regulatory regime*".[63] Aside from the impact on regulatory predictability, Option 1 would also be extremely complex to implement (requiring effectively two separate RAV concepts to be calculated and monitored/tracked over the coming decades, which itself will also contribute to the perception of increased regulatory risk; and creating significant complexity in, for example, the use of WACC to make time-value-of-money adjustments in the PCFM). Further, as Ofgem notes, this is likely to lead to a material re-profiling of long-term cashflows, increasing bills in the near term (offset by lower bills later on). Given there is no obvious customer-interest rationale for addressing the inflation effect, this re-profiling is unnecessary.
- In respect of **Option 2**, Ofgem says that this will continue to provide compensation for inflation via RAV indexation. This is incorrect – Option 2 fundamentally removes inflation protection by indexing part of RAV to a forecast rather than outturn inflation. The regulated entity will therefore be exposed to inflation risk under this Option. Ofgem may, nevertheless, see this approach as desirable and, in our view, Option 2 would be preferable over Option 1 on the grounds that it is less of a departure from the existing framework (albeit it still introduces material complexity); and with less material impact on cashflow profiles and investor risk. We note, however, that we strongly disagree with Ofgem's suggestion that the ILD assumption must be reduced to 0% under this Option – see further FQ3 below.)
- Whilst **Option 3** does maintain the structure of the current regime, we would urge Ofgem to give careful consideration with regard to changing the long-run inflation forecast used. The long-run inflation forecast must be genuinely and unequivocally forward-looking, not backwards-looking; and based on independent, widely recognised and respected forecasts, taken over an appropriate time horizon. The Bank of England continues to retain 2% as its inflation target and enacts policy to achieve this. This target (and therefore expectation) is embedded in UK markets and known to all market participants. In our view, there would therefore need to be a very strong reason to deviate from the OBR's forecasts which reflect this. Additionally, regarding Ofgem's suggestion of potentially using the break-even inflation in place of the long-term OBR forecast as the inflation assumption, we note that break-even inflation is known to overstate inflation expectations due to the inflation premium contained in nominal gilts. This and other potential issues with the break-even inflation have been well-documented as a part of the RIIO-2 debate - we believe that the same issues

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[63] Moody's (2023) Phoenix Natural Gas Limited, Update to credit analysis following final determination.

persist today, and Ofgem has not provided any evidence/reasoning for its apparent change in view as to the credibility of break-even measures of inflation. In addition, we refer to a Frontier Economics report[64] commissioned by the ENA which sets out some of the in-principle and practical problems with the break-even inflation as a long-term inflation assumption. More work needs to be done if Ofgem wants to find a "more appropriate" measurement for inflation assumption to replace the OBR forecast, with regard to the accuracy and predicting power of an alternative assumption. For example, if Ofgem firmly decides to move away from the current OBR year 5 forecast, a reasonable option could be a 20-year geometric average of a combined series using the five-year OBR forecasts followed by 15 years of the Bank of England target.

As a general observation on all the options, we also note that any change Ofgem adopts should be carefully calibrated to avoid introducing undue or material year-on-year volatility.

As Ofgem notes, any methodological changes would need to include appropriate transitional arrangements. We welcome Ofgem's recognition[65] that financing decisions taken to date could not have reasonably anticipated the sorts of changes Ofgem is now considering. We therefore agree that if a change is made, a suitable implementation mechanism is essential. Ofgem describes 10-year+ implementation periods – in our view, it should be much longer, based on our understanding of the ILD positions currently held by companies. The implementation options will need further careful consideration should Ofgem decide to proceed with any of its three options.

Finally, we note that in respect of Option 2, Ofgem states that *"The drawback of this approach is that it would not better align the 'cash' element of the debt allowance with the cash costs of fixed-rate debt (and so would have no positive impact on financeability)."* We would strongly urge Ofgem to remove cash flow implications as a rationale/criteria for making any of these changes. Re-profiling of cashflows relative to the status quo, under any of these options, can only have short-term effects on financial metrics that will be counterbalanced by equal and offsetting long-term effects. Further, if Ofgem were to bring forward cashflows, this cannot be used to justify under-funding other aspects of the price control (for example, the WACC allowance or Totex allowances). A proper assessment of financeability must 'see through' these short-term impacts on financial metrics and resist the temptation to calibrate other parts of the price control based on an illusion of financial 'headroom'.

FQ3. Do stakeholders have views on the potential approaches to implementation of the proposed methodology changes, including assumptions relating to ILD weights?

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64 Frontier Economics (March 2024). "Initial consideration of break-even inflation for price control purposes".

65 RIIO-3 SSMC Finance Annex, para 2.45.

The proposal to change the notional company assumption on ILD to 0% could introduce a number of problems:

- It introduces an uneven need to converge to such a position across the sector, with some companies already at that assumed level and others substantially away from it. This can create winners and losers based on arbitrary assumptions which significantly differ from those applied at RIIO-1 and RIIO-2, even if mitigating transitional arrangements are put into place to try to alleviate this.
- If the transitional arrangement is not designed to account for the RIIO-2 financing profile of the notional company and how exactly existing ILD would retire from the debt book, then there is a risk that companies would be penalised for financing decisions that they have efficiently taken in the past to match the regulator's own assumption.
- For example, if the transitional arrangement assumes that ILD will expire in 15 years, but the company has justifiably taken out a 30-year nominal-CPIH swap in the belief of an enduring 30% ILD notional-company assumption, then the company would be penalised for following the regulator's own past guidance.
- Only the transition option (c) where the inflation assumption is aligned to the actual company portion of ILD permanently does not create the above issue. But this also depends on what 'permanently' means. If it means that the assumption is fixed to the current portion, then that would also limit companies' future financing strategy. If it means that the assumption is automatically adjusted to reflect the actual portion as it evolves in time, then the question is how often will this calculation need to be reset within the price control period to ensure the true reflection of this without undue regulatory burden.
- It effectively dictates that companies should not take ILD in future, because any such debt would introduce inflation risk to financing costs. This would represent a regulatory intervention into companies' financing strategy, which contradicts a long-standing principle that Ofgem maintains for RIIO-3: *"As with previous price controls, we consider it appropriate that the risks and rewards arising from financing decisions reside with equity investors"*[66]. Moreover, it does not necessarily incentivise the most efficient financing decisions.
- Furthermore, a lower assumption of % of ILD in the notional company for Option 2 would create extra financeability challenges as there will be more assumed interest cost within a year. Ofgem should not seek to "address" such challenges by inappropriately tweaking the dividend level or the notional gearing level down.

FQ4. Do stakeholders wish to propose any other alternatives that have not been proposed?

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66 RIIO-3 SSMC Finance Annex, para 5.2

At this point in time, we do not have further proposals to put forward. However, we welcome further detail from Ofgem, particularly on the proposed weighted average approach, and the opportunity to provide subsequent input on this. We consider that the complex and technical aspects of the proposed changes to the calibration of the (weighted) cost of debt allowance methodology and its interaction with other elements of the price control (e.g. regulatory depreciation) warrant continued discussion and assessment in close collaboration between Ofgem and GDNs on a working group expert level. We would welcome it if Ofgem offered such an opportunity following the RIIO-3 SSMC response deadline.

FQ5. Do stakeholders have any additional evidence for us to consider in our review of the additional borrowing allowances or infrequent issuer premium?

We agree with Ofgem's proposal to continue providing allowances for the additional costs of borrowing and an infrequent issuer premium. We would highlight that the latest evidence shows a greater uplift for additional borrowing costs relative to RIIO-2. NERA has provided an independent assessment of the Additional Cost of Borrowing for the RIIO-3 Price Control for an average energy network[67] and also estimated some aspects of the impact of GDNs' reduced debt tenor on the Additional Cost of Borrowing[68]. NERA estimates additional costs of borrowing and the small company premium for RIIO-3 by using energy networks' latest data and market evidence, but notes that the estimate would need to be revisited, e.g. in light of Ofgem's decisions on financial resilience measures and notional assumptions and updated for changes to financial market conditions. A summary is provided below, but we refer to NERA's report for full details.

Transaction costs

NERA has considered data on transaction costs by looking at underwriting fees, bond advisory fees, arrangement fees, rating agency fees, legal fees, auditor fees and listing fees. It has considered whether companies must pay these upfront and/or on an ongoing basis and converted them into a cost that is to be recovered as an annuity over the life of the bond. Transaction costs were found to be 6bps on average (based on an average energy network companies' historical transaction cost data, which reflects an average tenor of around 17 years), with 50% of annualised fees required to be paid upfront.

In addition, NERA also highlights that *"GDNs face higher risks over RIIO-3 than historically, given concerns about future role of gas networks from decarbonisation of heat"* and goes on to state that *"recent evidence shows GDNs' debt tenor at issuance has shortened to around*

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67 NERA (February 2024). "Additional Cost of Borrowing for the RIIO-3 Price Control".

68 NERA (March 2024). "Impact of GDNs' Reduced Debt Tenor on Additional Cost of Borrowing at RIIO-3"

10 years".[69] Shorter tenor debt implies that GDN's RIIO-3 transaction cost will increase, from 6 to 8.5 bps, given the amortisation of up-front fees over a shorter life.

Liquidity/Revolving Capital Facilities (RCF) costs

Liquidity/RCF costs are estimated to be 13bps, comprising upfront arrangement fees, legal and agency fees, commitment fees on undrawn facilities and utilisation fees on drawn amounts. Ofgem does not currently include potential draw-down costs, previously assuming that the "*RCF is not drawn down and that any draw-down costs would be covered through the calibration of the debt allowance*." However it is incorrect to assume that the notional company would not draw down any RCF – NERA estimates draw-down of notional facility of around 15% based on company data, which is to meet operational needs and is therefore not remunerated through notional debt financed RAV*cost of debt. We note that the interest cost on the liquidity facility estimated by NERA (based on SONIA + 45bps) has substantially increased due to a steep increase in the SONIA rate since 2021.

It is also important to note that 13bps p.a. is likely to understate liquidity costs were Ofgem to implement proposed financial resilience measures, particularly in relation to the SSC A37 availability of resources certification requirement, which could increase the relevant period from 1 to a minimum of 3 years, but potentially to 5 years.

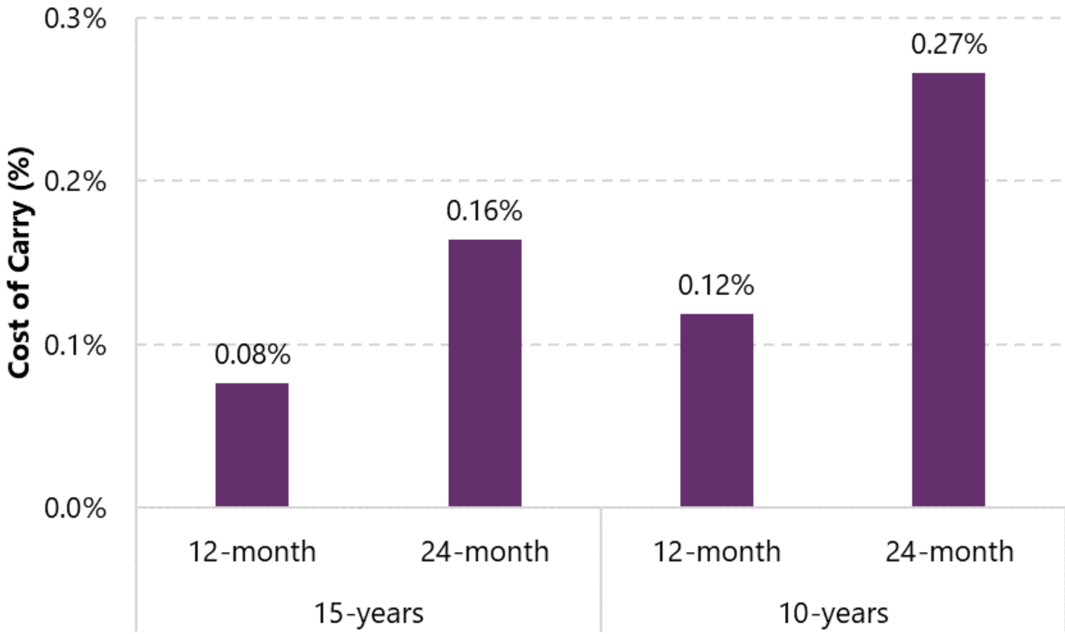
Cost of carry

NERA estimates the cost of carry for an average energy network to be 12 bps p.a., with a cross-check showing a range of 8-16bps.

For GDNs at RIIO-3, assuming carry costs are amortised over a 10-year bond tenor, the cost of carry increases to 12-27bps p.a. (midpoint 19 bps), as shown in Figure 7:

69 NERA (March 2024). "Impact of GDNs' Reduced Debt Tenor on Additional Cost of Borrowing at RIIO-3", page 3

Figure 7. Cost-of-carry higher for GDNs at RIIO-3, as cost amortised over a shorter tenor



Source: NERA analysis

As with liquidity costs, this estimate is likely to understate the cost of carry at RIIO-3, if Ofgem implements some of the new financial resilience measures, considered in RIIO-3 SSMC.

<u>*CPIH Premium*</u>

Ofgem recognised CPI/H switching costs of 5bps p.a. at GD/T2 and ED2. At ED2, Ofgem assumed 30bps p.a. for new CPI-linked debt issuance, and 15bps p.a. for managing existing RPI-CPI basis risk – with these values then being multiplied by the proportion of ILD issuance assumed and the proportion of new/embedded debt. However, in the RIIO-3 SSMC Ofgem states *"we intend to consider what adjustments are required to the Consumer Prices Index including owner occupiers' housing costs (CPIH) issuance/basis mitigation allowance given the anticipated migration of the Retail Price Index (RPI) inflation measure to the CPIH methodology from February 2030. This adjustment is likely to include the removal of the allowance from 2030."*[70]

We disagree with Ofgem that this allowance should be removed due to RPI and CPI(H) alignment from February 2030. As NERA outlines, CPI/H issuance and basis risk mitigation allowance should continue because:

[70] RIIO-3 SSMC Finance Annex, para 2.19

- Companies could face transition costs from having to compensate bondholders for a fundamental change in a bond's index, where the real coupon may have to be increased to ensure the investor is no worse off as a result of the change;
- Companies will also face costs associated with negotiating these changes with bondholders and making changes to documentation, which may require a consent solicitation process. At a minimum, these costs would include legal, trustee, agency and administration/tabulation fees and, at a maximum, would also include any fees paid to banks for running a consent solicitation process;
- These elements could therefore expose companies to costs substantially higher than in the status quo, as discussed below.

NERA considered data on two recent CPI-linked bonds and collected information on bank quotes for the costs associated with issuing CPI-ILD or swapping nominal to CPI. NERA also undertook discussions with the companies around CPI-CPIH basis risk mitigation. Based on this, NERA estimated the CPIH issuance and basis risk mitigation cost to be around 18-23bps for RIIO-3.

We note that the removal of CPIH mitigation risk is not justified even if Ofgem adopts either Option 1 or Option 2 of the inflation/indexation approach discussed above in FQs 2-3. Under Options 1&2 there will be a transition period during which the notional company will still hold ILD; and during which there will still be a need for the notional company to hedge part of its debt to CPI(H), which will continue to incur a cost.

Therefore, despite the planned alignment of RPI with CPI from 2030, Ofgem must provide an allowance for CPIH premium in RIIO-3 and potentially thereafter as discussed above.

New issue premium

NERA's evidence continues to support the existence of a new issue premium (i.e. a 'negative halo effect', contrasting the positive halo effect Ofgem considered existing at RIIO-GD2). The latest evidence indicates that the NIP has increased in recent years, with average premiums in the Utilities sector increasing to 10-19bps in 2022-2024 (relative to 4-6bps in 2020). The CAA also included a new issue premium for H7 of 15bps.

Given the latest market data and recent precedent, NERA suggests the current new issue premium is approximately 15bps for an average energy network. However, it should be noted that NIP in GD is likely to be higher in RIIO-3 than in ET/GT, hence requires separate consideration and a detailed analysis in light of the existing and emerging gas-specific debt market evidence.

Small Company / Infrequent issuer premium

We agree with Ofgem's proposal to continue with the infrequent issuer premium. The latest data based on analysis from NERA suggests this premium should be in the range of 10-18bps.

Summary

In a report for all energy networks, NERA estimated an additional cost of borrowing of 71 bps p.a. over RIIO-3. For GDNs however, these costs are estimated to be higher i.e. at least 81 bps p.a., assuming GDNs issue shorter tenor debt over RIIO-3 of around 10 years given risks around the future role of gas networks.

Table 2. Additional Cost of Borrowing for GDNs (excluding any increase in NIP)

Units: bps p.a.	Ofgem RIIO -2	NERA (Feb 2024, all networks)	NERA (Feb 2024, GDNs/ reduced tenor of 10 years)	Comment on GDN specific cost relative to NERA industry-wide estimate
Transaction Costs	6	6	8.5	• Analysis of GDN data shows reduced tenor increases costs from 6 to 8.5 bps, given amortisation of up-front fees over shorter life
Liquidity/RCF Costs	4	13	13	• No change to industry wide estimate
Cost of Carry	10	12	12-27 (19)	• Cost-of-carry increases as pre-financing costs amortised over shorter bond tenor
CPIH Premium	5	18-23 (21)	18-23 (21)	• No change to industry wide-estimate
New Issue Premium (NIP)	0	5	5*	• Not addressed as part of this report
Additional Cost of Borrowing	25	54-59 (57)	57-77* (67)	• Excludes any increase in NIP to reflect heightened risk from decarbonisation of heat
Small Company/Infrequent Issuer Premia	6	10-18 (14)	10-18 (14)	• Assuming tenor of 10 years, Scotland, NGN, WWU, and three Cadent networks (London, North West, West Midlands) qualify, whereas Southern and Cadent East do not
Total	31	64-77 (71)	67-95 (81)	

Allowed return on equity

FQ6. Do stakeholders agree with our interpretation and proposed application of UKRN Recommendations 2-7?

UKRN[71] recommendations 2-7 set out the following:

- *Recommendation 2 - CAPM: Since the cost of equity is not directly observable, it must be estimated using a widely accepted method. Regulators should continue to use the capital asset pricing model (CAPM) as their primary approach for estimating the cost of equity.*
- *Recommendation 3 – Risk-free rate: To estimate the real risk-free rate (RFR) within the CAPM, regulators should use recent yields on the index-linked gilts (ILG), with a maturity which matches the assumed investment horizon for their sector.*
- *Recommendation 4 – Equity risk premium: Regulators should estimate the equity risk premium (ERP) within the CAPM as the difference between the total market return (TMR) and the risk-free rate (RFR). We recommend that the TMR should be primarily based on historical ex post and historical ex ante evidence.*
- *Recommendation 5 – Equity beta: Regulators should estimate equity beta for the notional company using comparable listed companies and standard regression techniques (i.e. ordinary least squares (OLS)). Where the listed comparator has different gearing to the notional company, regulators should continue to de-lever and re-lever the raw equity beta.*
- *Recommendation 6 – CAPM point estimate: The RFR, TMR and (re-levered) equity beta assumptions should be combined using the CAPM to produce a cost of equity range. The mid-point of the range should be used as the central estimate for the CAPM cost of equity.*
- *Recommendation 7 – Cross-checks: Cross checks may be used to sense check the CAPM derived point estimate. However regulators should only deviate from the mid-point of the CAPM cost of equity range if there are strong reasons to do so.*

There are a number of areas where the UKRN guidance needs to be interpreted and applied very carefully, particularly given the fundamental structural changes that have recently occurred in financial markets and in light of the latest evidence.

We provide a number of specific observations below relating to how the UKRN guidance should properly be interpreted and applied, drawing on the relevant consultant reports (see list in the Overview).

[71] UKRN (2023). UKRN guidance for regulators on the methodology for setting the cost of capital.

Recommendation 3

Ofgem notes that its RIIO-2 approach is consistent with Recommendation 3.[72] However, in respect of whether a convenience yield should also be included in the estimation of the RFR, Ofgem acknowledges that the UKRN guidance *"does not propose alignment to a particular stance"*[73].

There are two main estimates of the convenience premium that have been cited in UK regulation to date:

- The first is based on AAA-rated corporate bond yields. This approach was used in the PR19 redetermination, where the CMA estimated the RFR by taking an average of ILG yields and AAA-rated corporate bonds. The CMA relied on this on the basis that corporate bond yields represent a rate that *"is available to all (relevant) market participants"*[74].
- The second is based on academic literature. The UKRN report cites the paper by Diamond and Van Tassel[75] which estimates average convenience yields across different countries. Whilst these estimates only cover short-term time horizons (the authors look at bonds of 3 months to 2 years), these still provide an indication of the magnitude of convenience premiums. If anything, longer-term government bonds are more likely to be subject to convenience premium than shorter-term ones due to the demand from institutional investors.

In our view, the above represents strong evidence both from regulatory precedent and academic literature that a convenience premium should be included in the RFR. The quantification of the convenience yield should be the subject of a separate consultation, but we would welcome it if Ofgem could confirm in the SSMD whether it agrees in principle that a convenience yield should be applied (and if not, the reasoning behind that conclusion).

Recommendation 4

Historical ex-post vs historical ex-ante

UKRN guidance suggests that "*the TMR should be primarily based on historical ex post and historical ex ante evidence*". Ofgem proposes to use both methods for estimating the TMR. With respect to ex ante evidence, Ofgem suggests two specific methodologies:[76]

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72 RIIO-3 SSMC Finance Annex, para 3.27.

73 RIIO-3 SSMC Finance Annex, para 3.30.

74 CMA PR19 redetermination (2021), para 9.160.

75 Diamond & Van Tassel (2021), 'Risk-Free Rates and Convenience Yields Around the World (available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4048083)

76 RIIO-3 SSMC Finance Annex, para 3.57.

- the DMS compositional approach (referred to by Oxera as the 'decompositional' approach); and
- the Fama and French dividend growth model.

As explained in the Oxera report, the historical ex-ante analysis is generally less informative than an ex-post approach.

- This is primarily because of its subjective nature which requires a decomposition of the TMR into different elements including classifying which observed events are '*unlikely to be repeatable'*.[77]
- Moreover, as Oxera explains, the two ex-ante approaches identified above rely on the geometric average of the dividend yield as a starting point, requiring an uplift to approximate it to the arithmetic average rather than using the arithmetic average directly.[78] Consistent with Oxera, our view is that an arithmetic mean is more suitable than a geometric mean to average out historic returns. This is in line with the CMA decision in the PR19 redetermination, where the CMA stated that "*[…] in the absence of clear modelling of the regulator's decision, the most appropriate estimate to use is the arithmetic mean. […] On balance, we consider that using the arithmetic mean is preferable due to its simplicity and transparency*".[79] The academic literature also generally supports the use of arithmetic averages when computing required equity returns for valuation and capital budgeting purposes.[80]
- Finally, there are data availability and reliability issues with both Ofgem's suggested ex-ante approaches.[81]

For these reasons, we agree with Oxera that only limited weight should be given to ex-ante approaches. We also agree with Oxera that, for ex-post approaches, the arithmetic mean is more suitable than a geometric mean.

Treatment of inflation in historical returns

We agree with Ofgem's proposed data sources for adjusting historical returns for inflation,[82] namely using the Consumption Expenditure Deflator for the period of 1900-1949 and the ONS backcast data for the 1950-1987 period. To clarify, with respect to the ONS backcast data, our view is that the CPIH series should be used instead of the previously existing CPI backcast as it addresses some concerning errors found in the Bank of England's 'Millenium' dataset used for RIIO-2 estimates.

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77 Oxera (February 2024). "RIIO-3 Cost of Equity", page 48.

78 Oxera (February 2024). "RIIO-3 Cost of Equity", page 52.

79 CMA PR19 redetermination (2021), paras 9.326–9.328.

80 Oxera (February 2024). "RIIO-3 Cost of Equity", page 43.

81 Oxera (February 2024). "RIIO-3 Cost of Equity", pages 49 and 52.

82 RIIO-3 SSMC Finance Annex, para 3.49-3.50.

Relevance of cross-checks (Recommendation 7) for TMR

We note that Ofgem also proposes to "*consider a range of appropriate timeframes, averaging methodologies and potential adjustments in order to use historical data to provide an effective forward-looking estimate of the TMR*".[83] This does not appear to be reflected in the UKRN guidance. However, we agree with Ofgem that the UKRN guidance is likely to require some careful interpretation. In particular, as we have set out in the Overview and explain more fully below, there has been a fundamental structural shift in financial markets in recent times which needs considering in relation to UKRN Recommendation 4. In our view, a proper interpretation of the cross-check evidence (as required by Recommendation 7) implies that the range and point estimate for TMR should be higher than a strict application of the average of historical ex-post and historical ex-ante evidence (per Recommendation 4). We turn to the cross-check evidence (Recommendation 7) below, before returning to the implications for TMR in FQ7.

Recommendation 6

Recommendation 6 states that the RFR, TMR and (re-levered) equity beta assumptions should be combined using the CAPM to produce a cost of equity range. The mid-point of the range should be used as the central estimate for the CAPM cost of equity.

We agree with this as a starting point for the CAPM cost of equity for a "baseline" network company (as we highlight throughout our response, GDNs have a higher risk profile), which can then be adjusted per Recommendation 7 below. However, we note that the UKRN guidance retains a degree of room for regulatory judgment on defining the CAPM parameter range (for example, in deciding which particular pieces of evidence should be relied on to inform the CAPM cost of equity range, from which a mid-point is taken). In our view, it is critical that – when making these judgements – regulators must set out all their reasoning and underlying calculations/evidence with full transparency and take account of sector-specific risks. Regulators cannot and should not arbitrarily place undue weight on weak or selective evidence; or arbitrarily discard strong evidence when exercising their discretion in defining the CAPM parameter ranges.

To the extent evidence on individual parameters is unclear or could be biased, regulators should take that into account when applying Recommendation 6 i.e. it may not be appropriate to take the mid-point of the range if the overwhelming balance of evidence suggests that a number towards the top or bottom of the range is actually the more likely estimate of the 'true' cost of equity. We note, for example, that the gas sector is no longer represented in listed UK beta comparators, and this must be taken into consideration by Ofgem (see FQ9 below). Again, Ofgem must provide full transparency also in explaining how it has weighted together different sources of evidence for defining each underlying CAPM parameter.

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[83] RIIO-3 SSMC Finance Annex, para 3.52.

Recommendation 7

This states that *"cross checks may be used to sense check the CAPM derived point estimate. However regulators should only deviate from the mid-point of the CAPM cost of equity range if there are strong reasons to do so"*.

We discuss below:

- Requirement in principle to aim up;
- Cross-check evidence from ARP-DRP;
- Cross-check evidence from hybrid bonds;
- Other cross-check evidence.

The evidence overall demonstrates that there are strong reasons for Ofgem to deviate from the midpoint, consistent with the UKRN guidance.

Requirement in principle to aim up

We consider that it is imperative of good regulatory practice to aim up on the allowed equity return from the midpoint of the estimated COE range. This is because the consumer harm that would arise from setting the allowed return too low far outweighs the consumer harm that might arise from setting the allowed return too high. If the allowed return is set too high, customers pay slightly more on their bills than they would have, had the allowance been set at the true cost of capital. However, if the allowed return is set too low, companies are unwilling to provide new investment or maintain existing investment at the level that would be optimal, had the allowed return been set at the true cost of capital. The result in this case is a considerable consumer welfare loss. Given that demand for most regulated services is inelastic because these services are essential in nature, the welfare loss from under-investment is large. The need for aiming up was discussed extensively during the RIIO-2 appeal and we do not repeat our views here, noting also the views of others as submitted to the CMA. All of the same considerations continue to apply.

We also observe that there is increased parameter uncertainty for GDNs relative to RIIO-2, due for example to the absence now of a gas sector comparator in the standard UK beta sample; as well as due to the significantly increased volatility in financial markets. This greater parameter uncertainty means, in our view, there is a greater risk that the regulator could set the allowed return too low.

Cross-check evidence from ARP-DRP

Oxera's report explains how the cost of debt can be used as a benchmark for CoE estimates.[84] Oxera focuses on comparing a measure of the ARP (asset risk premium) with the DRP (debt risk premium). This is a valid cross-check of whether the allowed CoE is appropriately calibrated because it is derived from market data on observed debt yields rather than built up from a theoretical asset pricing model. Oxera's report also addresses comments on the

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[84] Oxera (February 2024). "RIIO-3 Cost of Equity", pages 75-76.

framework made in previous regulatory publications and presents improvements that Oxera has introduced since then.[85]

The application of the ARP–DRP framework, taking into account the pricing of debt risk over a five-year horizon, suggests that the appropriate point estimate of the CoE needs to be above the top end of the inferred Ofgem rolled-forward range from RIIO-2, as estimated by Oxera (i.e. 5.77%); and in fact close to the upper end of the Oxera CoE range (i.e. 6.48%).[86]

Cross-check evidence from hybrid bonds

The Frontier Economics Equity Investability in RIIO-3 report explains that relative to RIIO-2, the RIIO-3 cost of equity allowances must take into account both (i) the significant change in the macroeconomic environment and financial market context (e.g. the dramatic increase in the BoE base rate and gilt yields); and (ii) the increased risks faced by networks in RIIO-3. As part of this, it is essential to understand whether the allowed return on equity provides adequate returns relative to longer-term debt benchmarks.

Frontier proposes that hybrid bonds can therefore be considered a valuable cross-check.[87] The table below summarises the outputs from Frontier's analysis for the long-term cost of equity estimate. Frontier concludes that *"Our point estimate of the expected returns on equity implied from hybrid debt evidence lies at 8.7% in nominal terms (6.7% in real terms)."*[88] Frontier has validated this result with a number of sensitivity checks. This cross-check therefore implies that the top end of Oxera's range at 6.48%[89] is a reasonably conservative estimate of the level of equity return for a "baseline" energy network currently required for GD3, if the current environment continues.

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85 Oxera (February 2024). "RIIO-3 Cost of Equity", pages 77-82.

86 Oxera (February 2024). "RIIO-3 Cost of Equity", page 85.

87 Frontier Economics (March 2024). "Equity Investability in RIIO-3". Chapter 5 discusses the hybrid bond cross-check in full including explanation of what hybrid bonds are and why they represent a sensible cross-check.

88 Frontier Economics (March 2024). "Equity Investability in RIIO-3", para 157

89 Oxera (February 2024). "RIIO-3 Cost of Equity", page 85.

Table 3. Results of the hybrid bond cross-check

Value	Estimate
Hybrid bond spread to iBoxx (adjusted for default risk, at issue)	136bps
iBoxx £ Utilities 10Y+ (2023 average)	6.0%
Higher returns on equity (based on 50% equity-like)	2.7%
Nominal cost of equity	**8.7%**
Real cost of equity (CPIH deflated)	**6.7%**

Source: Frontier Economics (March 2024), "Equity Investability in RIIO-3"

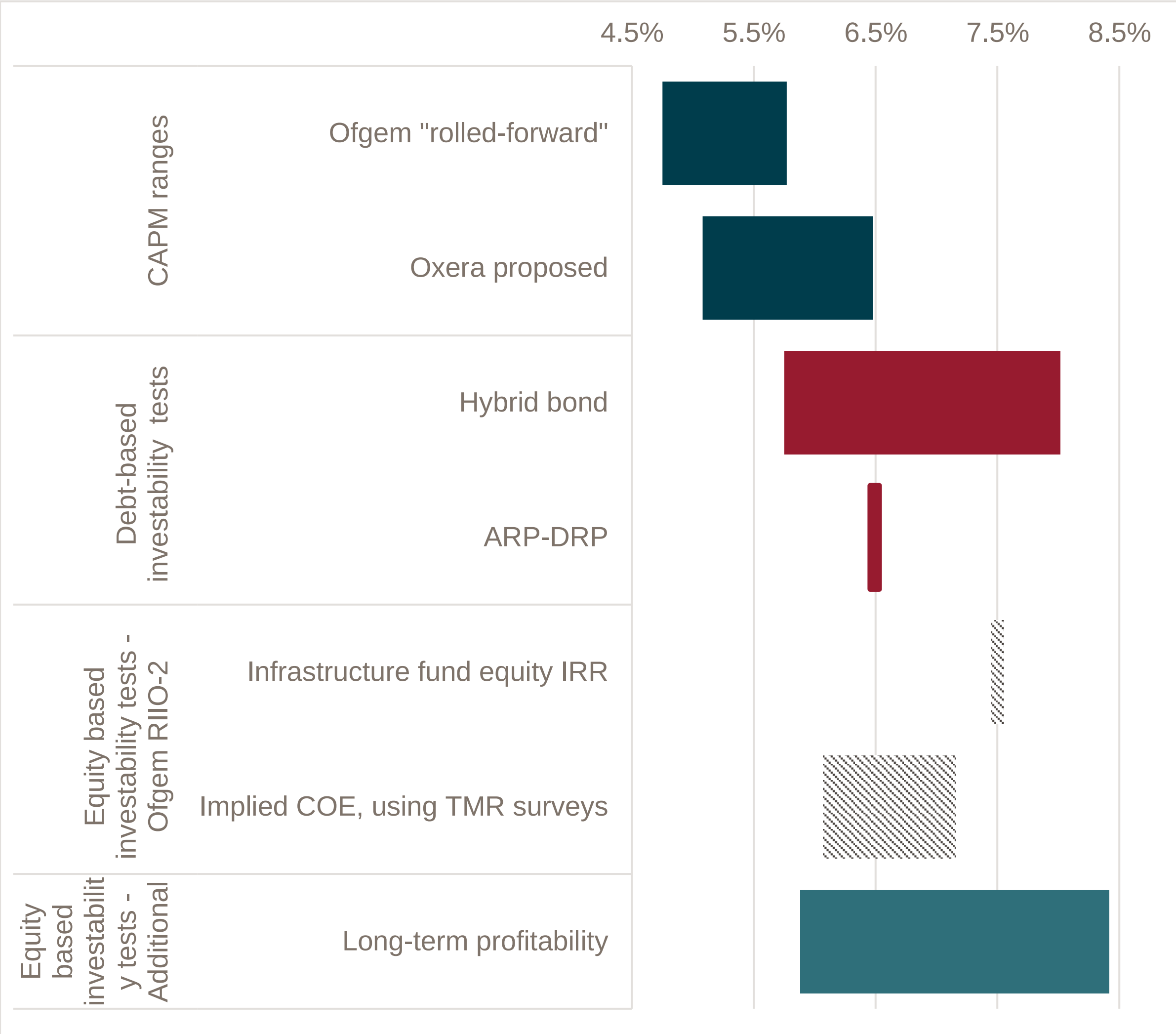
Other Cross-check evidence

Frontier Economics also presents the results of three equity cross-checks that it has been able to update using the latest evidence.[90] Two of these were relied on by Ofgem at RIIO-2 (Infrastructure fund IRR and COE inferred from investment manager forecasts of TMR, supplemented by the Fernandez survey) while one was not (the long-term profitability benchmark proposed by Frontier).

In summary, the results of all of Frontier's and Oxera's cross-check analyses are shown in the figure below, relative to the two 'baseline' COE ranges estimated by Oxera. Again, it is clear from a holistic assessment of the available evidence that the allowed cost of equity should increase relative to a simple roll-forward of the RIIO-GD2 methodology.

[90] Frontier Economics (March 2024). "Equity Investability in RIIO-3", Section 6

Figure 8. Investability tests of two COE ranges



Source: Frontier Economics (March 2024), "Equity Investability in RIIO-3"

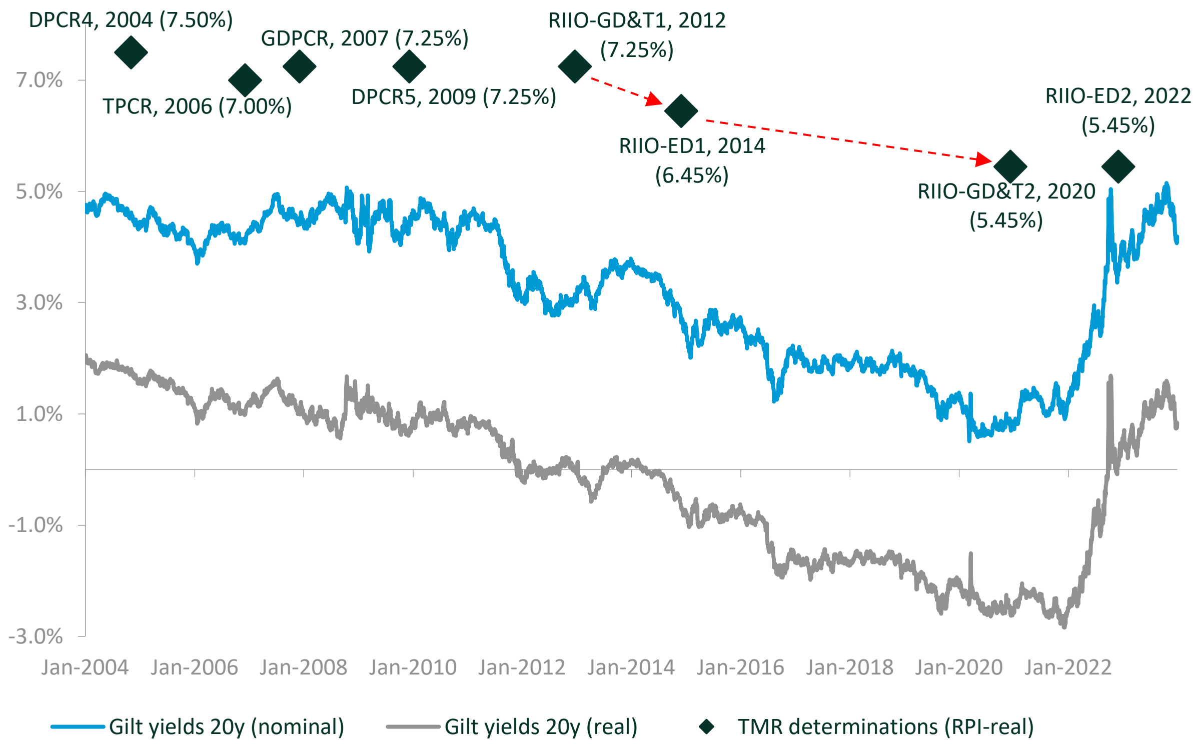
FQ7. Do stakeholders consider there to be good reasons to deviate from the respective approaches set out under UKRN Recommendations 2-7?

As explained in response to FQ6, the implications of the evidence arising from cross-checks under UKRN's Recommendation 7 mean there is a need for Ofgem to consider carefully how to interpret the other Recommendations. In particular, the cross-checks evidence, as well as Ofgem's own regulatory practice, provide a compelling reason for Ofgem to carefully interpret the UKRN approach, including when setting the TMR (Recommendation 4).

The UKRN guidance does not require the TMR to be fixed through the cycle - indeed, the guidance implies that the TMR can change over time, but that it is unlikely to move as materially as other parameters such as the RFR. The guidance states that stability in TMR *"does not imply that regulators should simply pick the same fixed value for the TMR in each decision for all time, but that the TMR would be relatively less variable than the underlying RFR."*[91]

As Oxera identifies, Ofgem's past TMR decisions have effectively followed this guidance – moving directionally in line with the changes in gilt yields over time. Oxera's figure is replicated below.

Figure 9. TMR determinations and gilt yields (RPI-real)



Source: Oxera (February 2024) "RIIO-3 Cost of Equity", Figure 2.6

As Oxera explains: *"It is apparent from the figure that Ofgem responded to the decline in gilt yields in the period 2010–21 by reducing the TMR allowance (in RPI-real terms) from 7.25% in 2012 to 6.45% in 2014 and 5.45% in 2020."*[92] Indeed, as highlighted by both Oxera and

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[91] UKRN (2023), 'UKRN guidance for regulators on the methodology for setting the cost of capital', p.19, https://ukrn.org.uk/app/uploads/2023/03/CoC-guidance_22.03.23.pdf (last accessed on 5 January 2024).

[92] Oxera (February 2024) "RIIO-3 Cost of Equity", page 53

Frontier Economics, regulators have been clear that the reduction in allowed TMR over time has been driven by their perception of wider market evidence, in particular interest rates.[93] Moreover, Frontier observes that real long-term equity returns as published by DMS, using the methodology and data which was standardly used by regulators prior to RIIO-ED1, have fluctuated in a narrow range roughly between 7.1% and 7.3% (in real terms according to DMS's definition of inflation for the UK) over 2010-2022 - i.e. TMR estimated on this long-run basis has barely changed.[94]

The TMR allowance, therefore, has followed interest rates downwards rather than remaining fixed. Since early 2022, however, long-term gilt yields have sharply increased, reaching levels last seen during 2005–11, as shown in Oxera's chart. In that previous window, Ofgem's TMR was between 7.0% and 7.25% (RPI-real) – equivalent to a CPI-real TMR greater than 8%. We agree with Oxera and Frontier that a consistent regulatory approach over time implies an increase in the TMR assumption in RIIO-3 relative to RIIO-2 – TMR allowances fell when interest rates fell, and it must now rise as interest rates have risen.

We note that Oxera recommends an increase in the TMR to a recommended range of 6.5% – 7.5% with a point estimate of 7%.[95] This is a comparatively small change in the context of the observed increase in UK government gilt yields (i.e. 15% of the increase in gilts[96]). It would be a less significant change in the TMR compared with Ofgem's response to changes in interest rates in the past, while also being consistent with the view that the TMR is broadly stable.

FQ8. Do stakeholders agree with our proposed methodologies where not specifically covered by the UKRN Guidance recommendations or our approach in previous price controls, such as the proposed approach to converting the RPI-real yields to CPIH-real inputs in the RFR calculation?

No, we do not share Ofgem's views, neither in terms of the RPI/CPI/CPIH wedge nor in relation to rejecting the need to compensate investors (incl. via WACC) in the gas distribution sector for the additional risks they bear on the path to Net Zero.

There are two important topics not covered by UKRN guidance:

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93 Frontier Economics (March 2024). "Equity Investability in RIIO-3", Section 2.1.1; Oxera (February 2024) "RIIO-3 Cost of Equity", pages 53-54.

94 Frontier Economics (March 2024). "Equity Investability in RIIO-3", para 58, and Figure 2

95 Oxera (February 2024) "RIIO-3 Cost of Equity", page 56.

96 Oxera calculates the increase in gilt yields between 8 December 2020 (the date of the publication of the RIIO-GD&T2 final determinations) to 20 December 2023 to be 332bps. The increase from the midpoint of the TMR range of 6.25–6.75% in RIIO-2 to the midpoint of Oxera's TMR range of 6.5-7.5% is 50bps. The percentage increase reported by Oxera is therefore 50bps divided by 332bps which is approximately 15%. Oxera (February 2024) "RIIO-3 Cost of Equity", footnote 99 and page 55.

- As the question notes, the UKRN guidance does not provide recommendations on converting RPI-real parameters to CPIH-real inputs; and
- The UKRN guidance is, by definition, concerned with how to reflect generic cross-sectoral issues underpinning standard WACC calculations. The UKRN guidance therefore does not touch on how sector-specific risks should be addressed – and in particular, whether and how to allow for asymmetric downside risks currently faced in the gas sector. This is a critical issue for RIIO-GD3 and it is an area where Ofgem will need to develop and apply its own methodology, rather than rely on anything in UKRN.

We discuss each of these in turn below.

Converting RPI-real yields to CPIH-real inputs

Our view is that the proposed approach to converting the RPI-yields to CPIH-real inputs requires further consideration, both in terms of the RPI to CPI and CPI to CPIH conversion.

First, we do not consider it justifiable to assume that the wedge between CPI and CPIH is zero. Ofgem notes that, historically, CPI and CPIH rates of inflation have been 'very close' on average - it specifies that CPI was, on average, 14bps higher than CPIH between June 2013 and June 2023[97]. Oxera in its CoE report evidences that the difference between CPI and CPIH since 2006 (i.e. since the start of the official CPIH index data), over the last three years and over the last five years respectively, was significantly higher than 14bps —at 19bps, 57bps and 33bps respectively.[98] NERA estimates the CPI/CPIH wedge using rolling standard deviations of CPI/CPIH wedge at 40-50 bps, with 50 bps based on the last 5 years of data, and 40 bps based on long-term data.[99]

Therefore, assuming that the CPI/CPIH wedge is zero when in fact CPI has been on average higher than CPIH over different estimation windows would result in allowances being over-deflated (in terms of the CoD) or under-inflated (in terms of the RFR) and ultimately lead to lower real allowed returns. Our view is that an adjustment for the difference in CPI and CPIH is needed.

Second, in the RIIO-3 SSMC, Ofgem has proposed to calculate the wedge using official forecasts of CPI and RPI up to the point of convergence of RPI and CPIH rates (which is assumed to be February 2030), and a zero wedge for the period ranging from the point of convergence to the maturity of the ILG being used for the estimation of the RFR, which we

97 RIIO-3 SSMC Finance Annex, para. 3.39

98 Oxera (February 2024) "RIIO-3 Cost of Equity", page 33.

99 NERA (February 2024), "Additional Cost of Borrowing for the RIIO-3 Price Control", p.12

understand to be 20 years[100]. In other words, it appears that Ofgem has proposed to follow the 20-year inflation forecast approach that it considered in RIIO-ED2 but did not use.[101]

Oxera has estimated the RPI/CPI wedge, based on Ofgem's proposed methodology, to be 0.32%. Additionally, it provides an estimation of 0.47% for the wedge based on RPI and CPI swap rates and uses that in addition to Ofgem's '20-year inflation forecast' methodology for Oxera's preferred wedge estimate. The average between the two estimates results in a point estimate of 0.39%[102].

Reflecting asymmetric downside gas-sector risk

As outlined above, the UKRN guidance is, by definition, concerned with how to reflect generic cross-sectoral issues underpinning standard WACC calculations. The UKRN guidance therefore does not touch on how sector-specific risks should be addressed – and in particular, whether and how to allow for asymmetric downside risks currently faced in the gas sector.

This is a critical issue for RIIO-GD3 and it is an area where Ofgem will need to develop and apply its own methodology, rather than rely on anything in UKRN. As set out in the Overview section above, we consider that there is clear evidence that the stranding risk faced by gas networks has increased; that the risk is asymmetric; and that the risk needs allowing for over and above the standard CAPM WACC allowance if Ofgem is to secure investability and financeability of the GD sector.

Ofgem's SSMC states that it is neither *"appropriate or necessary to increase allowed returns on capital in compensation for this perception of increased risk to the long-term value of the RAV. Increases in the allowed returns on capital would increase consumer bills which may ultimately prove to be unnecessary with greater clarity, such as around the approach to RAV recovery or on government policy, in future periods. This suggests that consumers would be funding increased returns to investors for no tangible benefit, which would not be in the consumer interest."*[103]

We would strongly disagree with the above statement. Notably, Ofgem's statement recognises that there is indeed a perception of increased risk to the long-term value of the RAV; and that there is no clarity as it stands on government policy in respect of RAV recovery. Those are exactly the circumstances that necessitate a cost of capital uplift. Ofgem is incorrect that customers would receive *"no tangible benefit"* – if stranding risk is not compensated and this results in a proposition that is no longer investable for debt and equity investors or risks financeablility challenges, this will result in significant risk of underinvestment and detriment to customers. There is therefore a clear and direct customer-

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100 RIIO-3 SSMC Finance Annex, para. 3.39

101 RIIO-ED2 Final Determination, Finance Annex, para 3.17. https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20Finance%20Annex.pdf

102 Oxera (February 2024) "RIIO-3 Cost of Equity". Prepared for Energy Networks Association, pages 32-33.

103 RIIO-3 SSMC Finance Annex, para 8.15

interest rationale to reflect the risk appropriately. Statements from the regulator such as the one above only compound the perception of risk, since it implies the regulator is unwilling to appropriately reflect and account for risks that are actually faced.

As set out in the Overview and in response to FQ1, there is already clear evidence of a debt cost premium being required, and this should be factored into our cost of debt allowance (consistent with the UKRN guidance). The implications of this debt market evidence can be extended to the required return on equity, i.e. it implies a premium is also required on the allowed return on equity for gas networks, on top of the baseline allowance.

This section therefore focuses on how Ofgem could calculate a cost of equity uplift, on the assumption that debt costs are fully recognised. We note that, if Ofgem prefers not to provide for separate direct debt and equity uplifts, then the broad framework set out here could be applied to derive an overall WACC uplift.

Ofgem also indicates that there are *"practical constraints to assessing and implementing an adjustment that was suitably commensurate with the perception of risk."* While we recognise quantification is challenging, we have developed a preliminary modelling framework to quantify a cost of equity uplift which would provide relevant risk compensation to investors.

We consider it possible to quantify the stranding risk by estimating an expected (i.e. probability-adjusted) loss which could arise in a stranding scenario. We have developed a framework for doing this which includes the following steps.

Step 1: Develop a projection of long-term cashflows extending to a given date (e.g. 2050) under a set of plausible scenarios. This can be obtained by assuming a high-level expenditure profile that could be associated with a given scenario and applying it in the existing regulatory RAV model to generate revenue projections. The results will naturally vary depending on a chosen depreciation policy, hence clarity from Ofgem on this front is paramount in the risk quantification exercise.

Step 2: Calculate the achieved Internal Rate of Return (IRR) of investors in scenarios where stranding arises. The stranding arises as a result of:

- customer bills being constrained (for example, this may be necessary to avoid what Ofgem describes as *"feedback loops associated with consumers leaving the market"*[104]*)* - meaning bills cannot rise sufficiently to enable full recovery of allowances, therefore giving rise to some unrecovered revenue; and
- a proportion of the closing RAV remaining unrecovered at the end of the assessment period, e.g. in 2050. Clearly, in some scenarios, the achieved IRR is below the required WACC (for the purpose of this framework, the value of the required WACC is not important, hence can be assumed to be equal to a CAPM-estimated WACC).

[104] RIIO-3 SSMC Finance Annex, para 8.23

Step 3: Calculate an allowed WACC uplift required from GD3 (therefore adjusting the projected future cashflows) that would be required to make investors whole – i.e. to give an IRR = (CAPM-estimated) WACC.

Step 4: Apply probability assumptions to each scenario, in order to estimate a required allowed WACC and/or Cost of Equity uplift accounting for the probability that stranding actually occurs (i.e. the expected or 'probability-weighted' loss).

We have applied this framework to a set of plausible future scenarios and found that the required WACC uplift to compensate for the asymmetric stranding risk faced by NGN is likely to be modest compared with the overall required WACC, but not negligible. The precise result will depend on the calibration of the model. Nonetheless, the framework clearly shows that, with a non-zero probability of stranding occurring, a WACC uplift will be required to compensate for the asymmetric risk that is faced. We reiterate that this is an asymmetric downside risk faced by the gas sector alone. We would like to invite Ofgem to work together on developing this modelling further and agreeing on suitable assumptions.

An alternative method is using Oxera's ARP-DRP framework. According to Oxera: *"[f]or example, if the DRP with the implied 'gas premium' is estimated to be DRP0 + 10bps, at a notional gearing of 60% this implies an increase in the ARP of (DRP0 + 10bps)/60% - ARP0, where DRP0 and ARP0 are the levels of DRP and ARP before the application of the 'gas premium'. This will provide an approximate ARP (as the sum of ARP0 and the increase in the ARP) that can be aimed for when setting the return on equity allowance."*[105]

We note that there are multiple international regulatory precedents on compensating investors for the stranding risk. Oxera's report on GDN risks and investability[106] identifies that Austria and France have allowed WACC uplifts/higher beta to compensate investors for bearing the stranding risk; while in New Zealand an additional ex-ante revenue allowance and a beta uplift have been made depending on the regulated sector. In France and New Zealand, these allowances were included alongside depreciation policy changes, resulting in cash-flow acceleration. Oxera finds that, with regard to the cost of capital uplifts or other specific ex-ante allowances compensating networks for the asset stranding risk, regulators have used the following:

- a 3.5% cost of equity uplift in Austria[107]
- an allowance of 10bps applied to the entire RAB in New Zealand (fibre)[108];
- a 0.05 uplift to the gas asset beta used in the calculation of the allowed cost of capital, partly attributable to the systematic component of the asset stranding risk in New Zealand (gas)[109];

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105 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.18.

106 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.42.

107 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.43.

108 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.51.

109 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.51.

- increased gas asset beta in France compared to previous regulatory periods, currently set at 0.45 (GD) and 0.47 (GT) for 2024–28, compared to 0.40 (GD) and 0.45 (GT) for 2016–20[110];

Finally, we agree with Oxera that *"A cost of capital uplift also has the advantage of being flexible: if uncertainty around the scale or the timing of the asset stranding risk is removed, the cost of capital uplift can be adjusted accordingly, or even removed, which ensures that there is no double-counting of the risk in favour of networks"*[111].

FQ9. What comparators and/or timeframes are likely to provide the most accurate estimate of beta for the energy network sectors on a forward-looking basis?

Below we first discuss generic issues which will affect what might be described as a "baseline" beta estimation methodology for RIIO-3, before going on to discuss GDN-specific issues with respect to beta.

Baseline beta issues

In terms of comparators for the UK GD sector, there is a clear lack of suitable listed companies in the UK that could serve as close proxies. Our view is that the current set of comparators, which includes National Grid, Pennon, Severn Trent and United Utilities, has to be expanded to include energy networks outside of the UK, for example elsewhere in Europe.[112] As the goal of an asset beta is to capture asset risk, we do not see strong arguments for why the asset risk between the UK and other European energy networks facing analogous challenges would be seen as less similar than the risk of two different industries in the same country, such as UK water and energy networks. Therefore, in the context of the paucity of relevant data for GDNs, Oxera has provided an updated set of the "baseline" beta estimates for a notional energy network (before accounting for sector-specific forward-looking risks). Oxera concludes that Ofgem's RIIO-2 asset beta range of 0.32–0.37, with a mid-point of 0.349, is appropriate for a baseline beta for RIIO-3 for an average energy network.[113] However, we consider that given GD-specific circumstances, this estimate can only serve as the bottom end of the beta range for GDNs in the UK (see further below a discussion of gas-sector-specific factors).

In terms of the suitable timeframe for beta estimation, there is no single right answer and there are advantages and disadvantages of focusing on the short, medium as well as long term. In general, any timeframe between 2 and 10 years can be a basis for a reliable estimate of beta. However, particular care should be taken with regard to the quality of estimates

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110 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p.51.

111 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.34.

112 Ofgem's advisers, CEPA, have endorsed the view that European energy networks are suitable comparators for UK energy networks (as noted in NGN's Notice of appeal, para. 185 - CEPA's Beta Estimation Issues Report (NGNNOA1_226)).

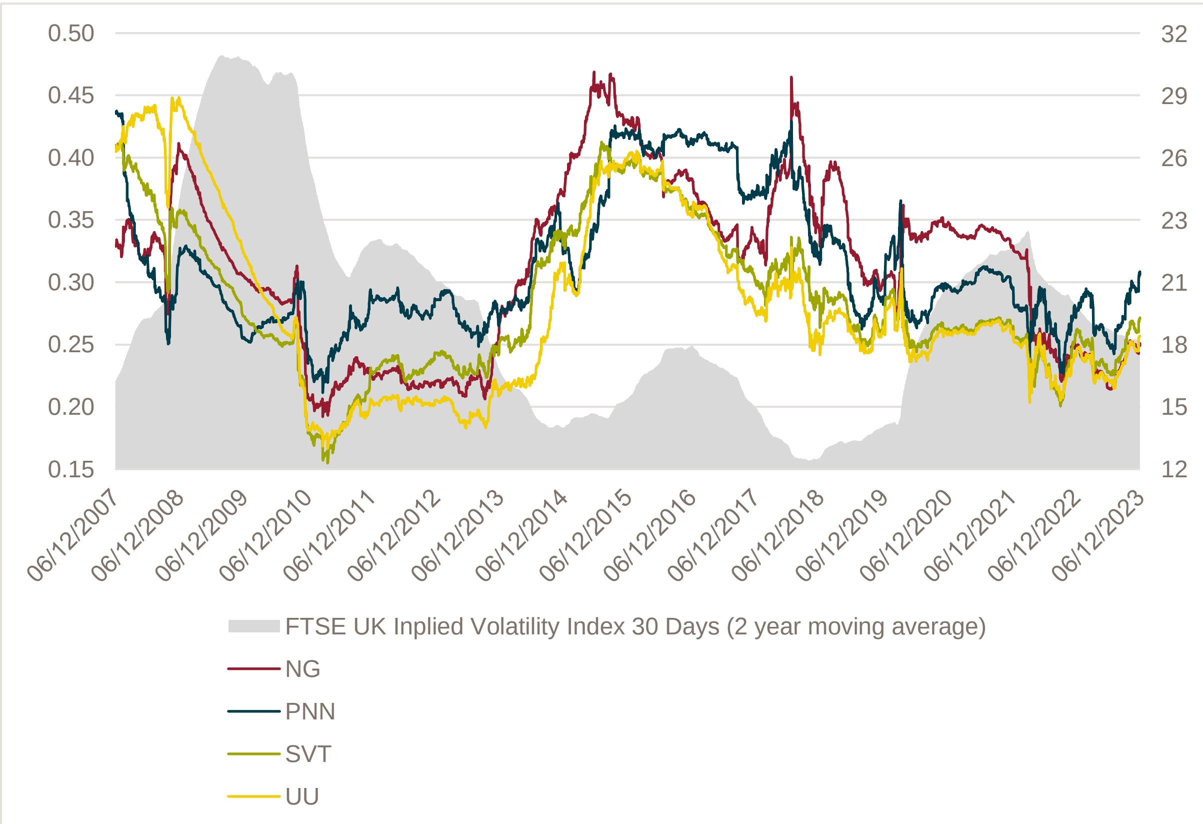
113 Oxera (February 2024) "RIIO-3 Cost of Equity", page 70.

within timeframes which include large macroeconomic events associated with extreme market volatility, such as the global financial crisis or Covid-19 pandemic or major geopolitical events. For stocks which typically exhibit below-market-average risk (e.g. utilities), including such periods in the estimation timeframe tends to cause betas to be demonstrably biased downwards.

Ofgem therefore should also give careful consideration to the fact that recent betas may be distorted to the downside. More specifically, they are affected by the degree of volatility in the index for the purposes of beta regressions.

This phenomenon is explained in detail in Frontier Economics' report on "*The low beta puzzle*". Volatility in the FTSE all-share index has increased markedly since c. 2019/20 (see chart below, which also shows that utility beta estimates tend to rise (fall) when market volatility is low (high).

Figure 10. 30d implied volatility and (unlevered) utility betas estimated using a 2-year estimation window



Source: Frontier Economics (March 2024). "The Low Beta Puzzle", Figure 1.

The evidence presented in the Fronter report shows that the current low utility betas (the low beta puzzle) may be caused by high market volatility.

In the context of the prevailing approach to setting allowed returns in the UK, this could present a problem. When setting the allowed equity returns, regulators have preferred to rely on a construct where the Total Market Return (TMR) is stable, albeit not fixed. UK regulators typically estimate the TMR and risk-free rate independently and directly and then infer the ERP as the difference between the two. The implication of this long-run approach is that the ERP in the regulator's CAPM formula moves in the opposite direction of the risk-free rate. Since the risk-free rate (typically proxied by yields on gilts) has risen materially in recent years, and since TMR will not increase one-for-one with RFR, within the UK regulatory construct, the inferred ERP will fall significantly which contradicts the findings in Frontier's paper that higher market volatility is typically associated with higher levels of ERP.

So at this time, when analysis of volatility suggests that it would be appropriate to assume that ERP needs to increase, the regulatory construct used by UK regulators without adjustment will instead impose an implicit assumption that it has decreased. This creates a real risk that required returns are underestimated. Viewed differently, the gilt yield has increased around 3.5 percentage points since RIIO GD2/T2, which means that the allowed TMR would have to increase materially more than 3.5 percentage points for the ERP to increase compared to GD2/T2 (a TMR of more than 10% in CPIH-real terms). It is clear that the effect of using beta estimates under high market volatility within the standard GB regulatory methodology would underestimate the cost of equity.

Frontier has also noted that some academics and practitioners take an even stronger view around the dangers of using betas estimated during periods of high volatility – it has been argued that these betas should not be used at all.

All of the above taken together means that Ofgem will need to take extra care when choosing a beta estimate for RIIO-3. Many of the shorter estimation windows are likely to be affected by estimation issues, and it would be wise to place as little weight as possible on periods of high market volatility. Of the candidate set of standard estimation windows, this consideration would point towards maximising reliance on 10-year betas at this time, although, if market volatility levels continue to tail off, then 2-year estimates may prove potentially less problematic down the line, subject to the usual due diligence around potential distortions.

Frontier also explains that reliance on 10-year betas is not without problems. 10-year betas are least likely to take appropriate account of emerging risks pertaining to the RIIO-3 period, i.e. this emerging risk will be heavily diluted by the use of 10-year betas, if such risks have only begun to be priced in recently. So, while market volatility might suggest that Ofgem should place less (or even no) reliance on 2 and 5-year betas at this time, 10-year betas may require uplifting to better reflect crystalising sector risk. We now turn to the evidence on gas-sector betas.

Gas-sector considerations

Ofgem has recognised that it might allow for differentiation in betas for different sectors if there is evidence of diverging risks.[114] Oxera's report on risks and investability of the GB gas distribution sector demonstrates that there is clear evidence that there is a difference between betas of gas and electricity networks[115].

Oxera's analysis looks into evidence from Spain and Italy which have both gas and electricity networks with traded equity shares. It finds that for two-, five- and ten-year measures:

- all but one reported betas of gas network companies are above the betas of electricity network companies in the same country; and
- on average, betas of gas networks are higher than those of electricity networks.

Oxera's results are replicated in Table 4 below. This clearly shows that there are systematic differences between gas and electricity network betas.

Table 4. Spot daily asset betas for European gas and electricity networks

Country	Company	Sector	Two-year asset beta	Five-year asset beta	Ten-year asset beta
Italy	Italgas	GD	0.33	0.35	n.a.
	Snam	GT	0.33	0.41	0.44
	Terna	ET	0.31	0.39	0.41
Spain	Enagas	GT	0.21	0.32	0.35
	Red Eléctrica	ET	0.21	0.26	0.32
	Average gas	GT&GD	0.29	0.36	0.39
	Average electricity	ET	0.26	0.32	0.37
	Difference in averages		0.03	0.04	0.02

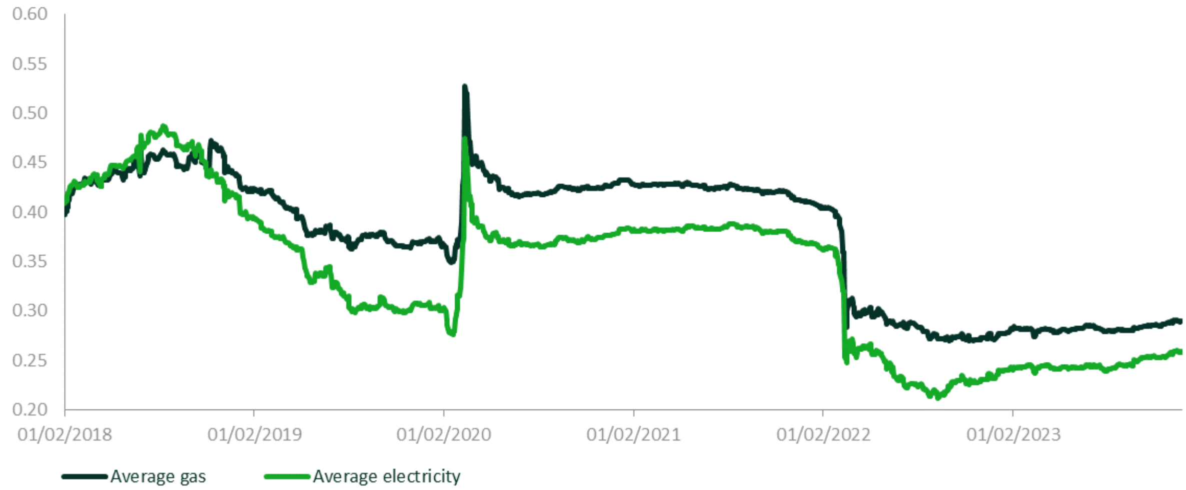
[114] RIIO-3 SSMC Finance Annex, para 3.75.

[115] Oxera (March 2024), "Risks and investability of the GB gas distribution sector"

Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.20.

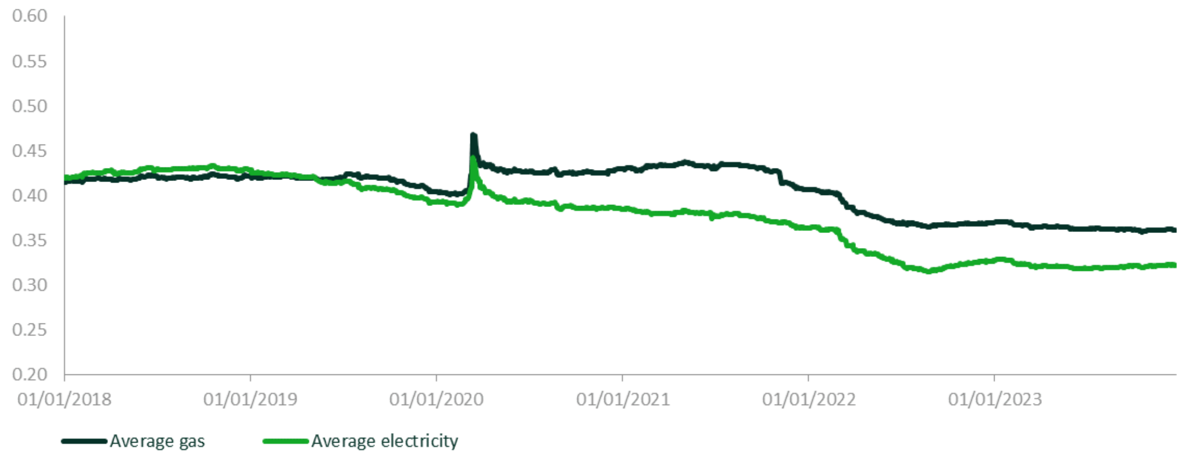
Oxera's report further shows that, based on the same sample of companies, on average, two-, five- and ten-year asset betas of gas networks have been higher than betas of electricity networks since at least 2019. Oxera's charts are replicated below.

Figure 11. Two-year daily betas of European gas and electricity networks



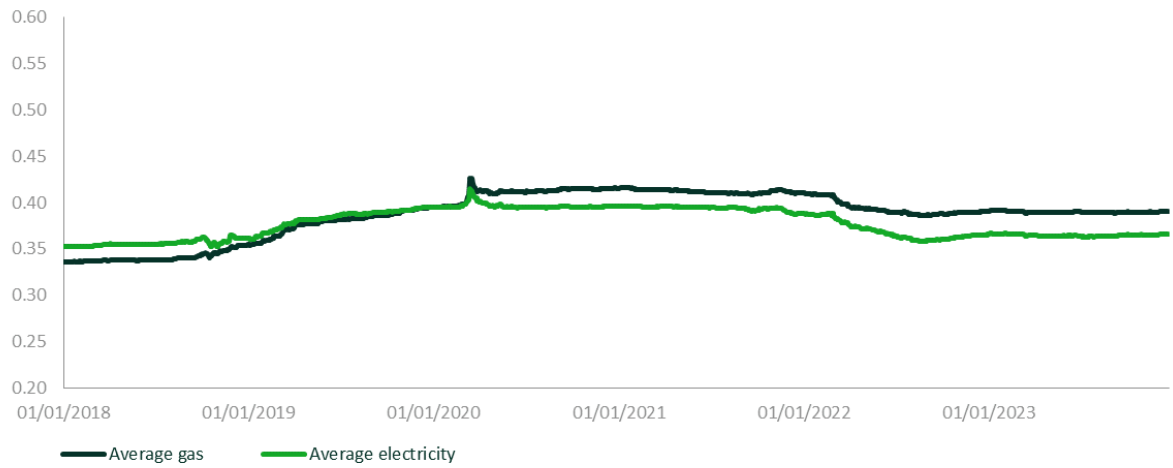
Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.21-22

Figure 12. Five-year daily betas of European gas and electricity networks



Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.21-22

Figure 13. Ten-year daily betas of European gas and electricity networks



Source: Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.21-22

Oxera explains that the asset-stranding risk faced by the GB gas networks is likely to include a systematic component.[116] The evidence in the table and figures above supports this, given that gas network betas tend to be higher than electricity network betas for these European assets. Oxera's report also compares the regulatory regimes (to ensure that the difference in observed betas is not driven by variation in regulatory regime); and confirms that the two sectors face similar differences in terms of Net Zero and the energy transition in these other countries, as is expected in the UK.

When setting WACC for the GDNs, Ofgem should therefore incorporate a beta uplift relative to the baseline energy network beta to reflect this alongside considering a WACC uplift for asymmetry (as discussed above) to fully compensate equity investors for the additional risk they bear. Oxera similarly concludes that *"alongside Ofgem's intended use of policy re-openers and depreciation policy to address gas sector uncertainty, it would be reasonable for Ofgem to consider the cost of capital compensation that is required for the remaining asset stranding risk"*[117]. In our view, Oxera's "baseline" beta estimate which it proposes would apply across all energy networks[118] is effectively a minimum reasonable beta that could be applied for the GDNs.

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116 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.14-15.

117 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.59.

118 i.e. as set out in the ENA-commissioned report, Oxera (February 2024). "RIIO-3 Cost of Equity".

Allowed WACC

FQ10. Do stakeholders consider there to be good reasons to deviate from the respective approaches set out under UKRN Recommendations 1 and 9?

These recommendations are as follows:

- *Recommendation 1 - Notional company: Regulators should continue to estimate the allowed rate of return in price controls based on the weighted average cost of capital for a notionally financed firm within their sector.*
- *Recommendation 9 – Gearing: The notional gearing assumption should reflect the regulator's assessment of the balance of risks facing the regulated company, a wide range of benchmarks on gearing levels, and overall regulatory policy objectives - not just the gearing level of the actual company (or companies) in question*.

We would emphasise that, in setting the notional structure, Ofgem must have regard to the actual company structures at least at a sector level. Failing to do so could mean that Ofgem makes assumptions in the name of notional efficiency but ignores the reality of what is and is not achievable.

Also, should Ofgem look to change the notional structure from one price control to the next, it needs to have a clear rationale as to why the underlying assumption of notional efficiency has changed consistent with principles of predictability and best regulatory practice. The notional capital structure should be independently justified and justifiable, and not be used as a lever to offset the effect of incorrect calibration of other parameters in the price control. In particular, this should not be used as a tool to obfuscate any underlying financeability issues.

FQ11. Do stakeholders consider there to be good reasons to deviate from the notional gearing assumptions (with respect to the level of gearing and the mix of debt types) applied to GD, GT and ET companies in the RIIO-2 price controls?

NGN considers it important for Ofgem to set a notional structure for the sector that reflects an efficient structure observed in reality by means of the sector average. This applies to both the gearing level and the proportion of ILD.

We see no reason for the notional gearing level to be set differently from the GD2 levels in the absence of strong evidence to the contrary, especially if this were to be set lower in order for the financial metrics to pass the target credit rating threshold. That said, if the actual/forecast GD sector average level of gearing remains higher than 60% by the end of GD-2, Ofgem may wish to consider whether a 5-year glide path to reduce notional gearing from 65% in RIIO-1 to 60% in RIIO-2 was sufficient or needs extending.

Equally, we do not see any justification to assume a 0% ILD in the notional structure. Companies have taken out ILD in order to optimise their capital structure, and in the case of NGN to match the regulatory assumption of the notional company (30%). It would be costly to have to suddenly unwind this structure only because Ofgem decides that a different proportion should be used (e.g. 0%).

FQ12. Do stakeholders agree with the proposal that notional gearing levels should be maintained for each year of the price control? Do stakeholders have a preference for how this assumption is managed within the price control process?

In its discussion of financial resilience, Ofgem states: *"For gas, the need to manage the pathway to net zero has potential implications for the trajectory of the RAV (which can have implications for gearing, for example). Whilst it is our expectation that responsible owners would use the majority of any accelerated depreciation in gas to de-lever and broadly maintain gearing levels, licensees have flexibility within the existing conditions to diverge materially from existing or notional gearing levels, subject to financial resilience requirements, if that helps to efficiently manage the reduction in debt levels."*[119]

If Ofgem were to decide to accelerate depreciation, this could lead to a different RAV profile than what has been expected and planned for when issuing long-dated debt in the past. As Ofgem rightly notes above, care will need to be taken to ensure that – in this context – the notional company is in fact able to maintain gearing levels over time, let alone in each year of the price control, at the level Ofgem assumes when setting the price control.

Of particular note here is that the long-dated debt which has been issued to date cannot necessarily be 'paid down' without incurring additional costs/early payment penalties. Therefore, Ofgem should be mindful of the real-world implications on networks if there are changes to regulatory depreciation policies.

By way of example, should Ofgem determine that accelerating depreciation would be the economically correct approach, depending on the extent to which this acceleration impacts the RAV, licensees cannot be presumed to automatically pre-pay debt with the cash surplus should it arise after financing all other expenditures. If Ofgem looks to accelerate RAV depreciation, an allowance for early debt payment penalties and other costs that are likely to be incurred by companies which had previously financed themselves efficiently (on the assumption of a consistent/predictable depreciation policy over time) will have to be allowed for and factored into financial modelling.

We also note that Ofgem should recognise that some part of the increase in cash as a result of accelerating depreciation could and should be returned to equity holders. This has

[119] RIIO-3 SSMC Finance Annex, para 6.12

implications for how Ofgem assesses the financeability and investability of a notional company (particularly if dividend levels are to be benchmarked).

We note that in RIIO-2, for the purpose of financial modelling, the level of notional gearing was set with reference to the start of the price control. If Ofgem contemplates changing this approach, clarity on many financial modelling assumptions is required, e.g. on the “notional” penalties for early debt redemption, assumed level of “normal” dividends, schedule of assumed return of equity capital and how this would interact with RAV, etc. We would welcome an opportunity to discuss these and other financial policy and financial modelling questions with Ofgem to develop a set of workable and implementable principles.

Financeability

FQ13. What, if any, improvements should Ofgem make to the assessment of financeability in the next price control?

Some clear improvements should be made in the financeability assessment.

First, Ofgem needs to embed a long-term view of financeability. This is particularly true if Ofgem is contemplating fundamental changes to price control parameters (such as the treatment of inflation or depreciation) which will have the effect of quite substantial re-profiling of cashflows over time. This long-term financeability assessment test should ensure the notional company is resilient to different long-term demand scenarios and long-term expenditure profiles. A long-term view of financeability is paramount given Ofgem's Net Zero duty and imminent Growth duty.

Second, Ofgem should ensure its financeability assessment is not limited to debt financeability (i.e. via exploration of the relevant credit metrics only). Equity financeability must also be considered – in particular an assessment of expected dividend yield.

As part of the KPMG's analysis of Credit Rating Agencies' perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond, CRAs considered it positive that Ofgem proposed extending the time horizons of looking at financeability. For the agencies, it was helpful that the regulator was looking longer term rather than just one price control. Crucially, CRAs underlined that they would monitor whether and how the regulator would be accounting for gas-specific risks, including in terms of reflecting them in the WACC allowances[120].

FQ14. What evidence, if any, should Ofgem consider in relation to expanding its assessment of financeability to account for 'investability'?

In its SSMC Ofgem sets out its intention to develop the notion of investability in order to "*better understand whether the allowed return on equity is sufficient to retain and attract the equity capital that the sector requires*".[121] We agree with Frontier Economics that investability is a concept that should be considered relevant for both debt and equity investors[122] – albeit recognising that many tools already exist at present to assess the proposition available to the debt investor (e.g. by assessing credit metrics and through rating

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120 KPMG (March 2024). "Credit Rating Agencies' perception of Risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond" (confidential)

121 RIIO-3 SSMC Finance Annex, para 1.6

122 Frontier Economics (March 2024). "Equity Investability in RIIO-3", para 33

methodologies developed by the rating agencies[123]). We therefore interpret Ofgem's Investability concept as being primarily (although not exclusively) relevant for the equity investor.

The need for proper consideration of investability at RIIO-3 is particularly driven by the very material change in capital market conditions that has occurred since the RIIO-2 price controls - in particular the T2/GD2 price controls - were set. In response to a variety of global shocks, the period of ultra-loose macroeconomic policy has ended, bringing with it an abrupt rise in interest rates and the cost of borrowing. These new conditions must be reflected in the updated allowed WACC for RIIO-3. The substantial changes envisaged in the GD sector, associated with the range of scenario uncertainty, also make this essential for RIIO-GD3.

We agree with the principles and tools that are proposed in the Frontier Economics report.[124] We note in particular that:

- Equity investors must rationally want to invest in the GD3 proposition when assessed relative to the set of other opportunities that exist in the wider capital market;
- At a high level, it is clear that the equity returns on offer must exceed those which can be achieved on debt. If the wedge between debt and equity returns shrinks to the point where it becomes irrational for an investor to be willing to invest in equity, which is by its nature higher risk, this must indicate that equity returns are insufficient;
- Well-designed cross-checks can play an important role in respect of equity investability – albeit these need to be designed robustly and interpreted subject to the relevant caveats/limitations associated with each cross-check;
- It is vitally important that investability considerations are not just limited to attracting new equity investment, but also recognize the importance of retaining existing equity investment. Ofgem's SSMC does recognize that both attracting and retaining equity is important[125], albeit elsewhere in the SSMC Ofgem seems to focus most of its attention on the need for '*fresh*' equity injections.

Oxera's report emphasises that investability is as important for the gas distribution sector as it is in electricity.[126] We agree with Oxera that the following issues are important:

- The concept of investability is as important for gas networks as for electricity networks because it is needed to ensure network resilience and an orderly transition to a decarbonised economy;
- There is a common pool of capital and cross-ownership in the UK energy sector, including gas and electricity networks as well as the assets that are potentially covered by the new areas of energy regulation (such as CCUS transport, new nuclear, and

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123 As explained in response to FQ 13, a key consideration for RIIO-GD3 will be that Ofgem needs to apply these existing tools with a long-term lens, to test resilience against the range of scenarios faced.

124 Frontier Economics (March 2024). "Equity Investability in RIIO-3"

125 RIIO-3 SSMC Finance Annex, para 1.6, 3.1, 5.9

126 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.53-57.

hydrogen). It is reasonable to assume that frameworks and decisions developed for GDNs in RIIO-3 will inform investor expectations across such assets, and over time. Thereby, any contagion effects and interdependence of the perceived risks to investability in the gas sector have the potential to 'spill over' across time, across the energy value chain, and across sectors that are subject to regulation by Ofgem;

- Investors can be expected to assess investability across a whole 'life cycle' of growth, stability and then a declining RAV. If Ofgem downplays investability during the latter phases, investors in infrastructure in the earlier phases will take note;
- There is very significant competition to attract capital into a wide range of infrastructure sectors. The gas sector needs to be competitive;
- Overall, alongside Ofgem's intended use of policy re-openers and depreciation policy to address gas sector uncertainty, it would be reasonable for Ofgem to consider the cost of capital compensation that is required for the remaining asset stranding risk, and undertake robust investability analysis for the gas sector.

Financial resilience

FQ15. What is your view on the proposed financial resilience measures? Are these appropriate and/or are there any other measures that you would propose?

We consider that the measures currently in place are adequate to provide Ofgem with oversight and assurance that regulated entities are financially resilient and have sufficient resources to maintain such resilience.

Table 2 of the RIIO-3 SSMC Finance Annex provides a helpful overview of the extensive list of existing RIIO-2 Licence conditions and protections aimed at ensuring financial resilience of Gas Distribution Networks (GDNs). These include:

- Standard Special Condition (SSC) A38: Credit Rating of the Licensee and Related Obligations;
- Standard Condition (StC) 45: Undertaking from Ultimate Controller;
- SSC A27: Disposal of Assets and Restrictions on Charges Over Receivables;
- SSC A35: Prohibition of Cross-Subsidies;
- SSC A36: Restriction on Activity and Financial Ring Fencing;
- SSC A37: Availability of Resources;
- SSC A39: Indebtedness;
- SSC A40: Regulatory Instructions and Guidance (RIGs).

We agree with Ofgem that "*In the round, we consider these financial resilience measures to have been broadly effective in helping to incentivise shareholders and management to maintain financial policies and outcomes that are consistent with a financially resilient sector*"[127].

However, we believe that most of the "*potential shortfalls*" with the current financial resilience regime identified by Ofgem[128] are overstated in the absence of any evidence that the sector is not financially resilient or that the current measures are not sufficient or effective. In particular, we consider that any perceived issues with the existing Licence conditions, should Ofgem be concerned about transparency and visibility of company-specific constraints, could be dealt with by providing further guidance or streamlining the existing processes.

For example, Ofgem is concerned that it utilises credit rating assessments by credit rating agencies. As long as the CRAs' judgement contributes to debt investors' assessment of credit quality and fair value (debt pricing) we do not share Ofgem's concern that this presents a problem. Conversely, we believe it is quite beneficial and in the consumer interest that credit

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[127] RIIO-3 SSMC Finance Annex, para 6.8.

[128] RIIO-3 SSMC Finance Annex, para 6.14

ratings are obtained following extensive analysis and review of an issuer's financial position, conducted independently by external CRAs. In addition, as part of the independent annual audit, external assurance is undertaken with regard to cross-subsidies and availability of resources. This should provide Ofgem with the assurance that credit ratings and Board assurances given to Ofgem as part of SSC A37 have been independently set or scrutinised.

NGN has always acted responsibly and prudently in terms of the financial policies in general and dividend policies in particular, hence we do not believe that Ofgem's reference to "*aggressive financial policies and instruments*" applies in our case and Ofgem should be mindful of looking to introduce further regulatory burdens on a one size fits all basis, without a proper impact assessment of the impact of any proposals and new licence obligations.

As regards Ofgem's concern that "*Board certifications around many of the measures in Table 10 (and the statutory going concern statement) are informed by a short term 12-month forecast, which provides minimal visibility into the longer-term viability of the Licensee*" and also its considerations about stress-testing, we consider that existing Licence requirements already provide for longer-term financial projections and stipulate stress-testing for the Licensee where these additional requirements are justified.

For example, Part C of SSC 38 (Credit Rating of the Licensee and Related Obligations) states that [emphasis added]:

*"4. The licensee must provide the Authority with a **Financial Resilience Report** within 60 days of 1 April 2021 or the date of a Negative Rating Action relating to the Licensee (whichever is later), if:*

a) the Licensee's highest rating held for an Issuer Credit Rating or highest rating held for a Significant Instrument Credit Rating is one notch higher than the lowest Investment Grade and that Issuer Credit Rating or Significant Instrument Credit Rating is on Negative Watch;
b) the Licensee's Issuer Credit Rating or Significant Instrument Credit Rating in at the lowest Investment Grade or lower, or
c) the Licensee has a debt covenant linked to a specific Issuer Credit Rating or Significant Instrument Credit Rating that would, if breached by the Licensee, trigger an event of default under the relevant debt documents and that rating is either:
    i. one notch above the minimum covenant requirement and is on Negative Watch; or
    ii. lower than one notch above the minimum rating specified within the covenant requirement.

5. The Financial Resilience Report must include:

*a) an assessment of the Licensee's current and forecast financial standing, including an **assessment of resilience to downside scenarios** relating to either operational performance or macro-economic events;*

b) ***financial projections for the next three Regulatory Years*** *(including the remainder of the current year) or* ***the remainder of the Price Control Period****, whichever is longer; and*
c) *details of Potential Mitigating Actions the Licensee could take to improve its financial resilience and an indication of whether such actions are planned.*

6. The financial projections required by paragraph 5(b) must include:

a) *a forecast balance sheet;*
b) *income statements;*
c) *cashflow statements;*
d) *key financial metric projections; and*
e) ***results of any stress tests*** *that the Licensee considers to be appropriate."*

We consider that these measures provide appropriate controls and rigour in assessing the financial resilience of companies and no further measures are required. Nevertheless, we provide additional observations below on the options Ofgem is considering.

Evolving Existing Financial Resilience Measures

Ofgem confirms that its intention is to evolve existing financial resilience measures to ensure consumers have the appropriate level of protection from downside risks. Our high-level comments on Ofgem's thinking include:

- Ofgem reiterates its RIIO-2 requirement for the companies to provide, as part of business plan submissions, accompanying certifications of financeability (on notional and actual capital structure bases) for the price control period which have an appropriate level of board assurance.[129] However, companies' ability to provide appropriate certifications relating to Ofgem's Financeability duty depends, to a significant extent, on the correct calibration of the financial package for RIIO-3, i.e. among other things the provision of WACC and cost allowances that ensure GDN investability and enable companies to meet or exceed the minimum thresholds of debt and equity metrics;
- Ofgem is considering how to manage the risks of high levels of leverage at MidCo and HoldCo companies that could negatively impact decision-making and the resilience of the Licensee and Ofgem's ability to have sufficient scrutiny over the decision-making around distributions and Licensee groups' financial structures.[130] In the context of the issues that some water companies have faced relatively recently, we understand Ofgem's motivation to prevent similar events from unfolding in the energy sector. However, water and energy networks and their shareholders differ in many respects,

[129] RIIO-3 SSMC Finance Annex, para 6.24

[130] RIIO-3 SSMC Finance Annex, para 6.25-6.28

and it would be wrong to be guided by negative press coverage in one sector (water) to infer a need for action in another sector (GDNs), where there is no evidence of a problem. As we further elaborate below, it is important for investor confidence that regulatory interventions are proportionate and well-targeted. In any case, we do not consider that these concerns apply to NGN. NGN currently has no external debt above the licensed entity, or indeed any kind of MidCo structure. Whilst there are shareholder loans in place (with NGN's immediate holding company as the borrower) these have equity-like characteristics that mean the servicing of this debt would not be reliant on "excessive" dividends from the licensed entity. Moreover, NGN has a relatively simple capital structure and any strategy decisions taken at the HoldCo level take full account of any impact on the Licensee.

- Ofgem indicates that it will review and consult on modifying the Regulatory Financial Performance Reporting (RFPR) Regulatory Instructions and Guidance (RIGs) for the 2023/24 reporting year[131] – we see no issue with regular reviews and evolution of the RIGs and the associated guidance documents in principle and will engage with Ofgem and respond in due course with our detailed observations during the upcoming consultation. Some of the trailed suggestions appear more straightforward (e.g. as regards disclosing to Ofgem existing debt covenant trigger events), but others, where the proposed changes are more fundamental or technical in nature (e.g. introducing a consistent template on distributions), will require debate and detailed working group-level discussions. We would encourage Ofgem to be open to introducing changes, should they prove to be strictly required, more gradually, perhaps deferring more fundamental ones to RIIO-3, to enable a higher level of rigour and comprehensive industry review.

Potential additional financial resilience measures

Ofgem outlines in Table 3 of the RIIO-3 SSMC Finance Annex its proposals to introduce three measures which it considers will increase its ability to monitor and measure the financial resilience of its Licensees. These are:

1. *Amend the licence condition to "require" Licensees to maintain more than one investment grade rating rather than "use reasonable endeavours" or "all appropriate steps".*
2. *Amend the dividend lock-up trigger to be the earlier of reaching BBB- with a negative watch/outlook and 80% regulatory gearing.*
3. *Amend the Availability of Resources requirement for board certification to require that the Licensee states that, based on agreed assumptions, it has sufficient financial resources to cover the entire price control period or a minimum of three years ahead.*

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131 RIIO-3 SSMC Finance Annex, para 6.29

At the outset, we would like to note that the primary basis for regulatory intervention should be the identification of a clear market failure and hence economic inefficiency that needs to be and can be remedied by regulation. Accordingly, the introduction of new regulatory tools and requirements necessitates a proper impact assessment and cost-benefit analysis, to understand the full scale of unintended consequences. Accordingly, leaving aside whether Ofgem's proposals would have a material impact on NGN based on its current circumstances, we do not see that a case for further intervention has been made, or any evidence that current licence conditions aimed at ensuring financial resilience are not working well or would not be effective.

We would therefore caution against introducing new obligations and thresholds for lock-up and regulatory reporting without a proper assessment of the policy objectives, whether there is a failure that needs addressing and quantifying the impact and scale of such failure against each of the options proposed to address it. In addition, a clear analysis of why the current set of regulatory tools falls short of addressing any such concerns and the case for intervention should be carried out.

We address each proposal in turn:

Proposal 1 relating to requiring more than one investment grade rating

NGN already maintains two investment-grade credit ratings and it is unlikely that this change would result in any direct impact on NGN or our customers. Since its incorporation, NGN has always maintained a responsible and prudent financing strategy. This is evidenced by our stable investment grade credit ratings, comfortably above the minimum level required by Ofgem: Baa1 from Moody's and BBB+ from S&P.

That said, if it is to become a Licence condition for a network operator to maintain investment grade credit ratings from at least two agencies, it will become even more critical that the overall price control settlement supports this from a financeability and investability point of view. In its financeability assessment therefore, Ofgem has to take account of the specific credit metrics and their rating thresholds, rating methodologies and the treatment of certain regulatory elements of the price control (e.g. depreciation, capitalisation rates, other cash-flow adjustments), which differ by Credit Rating Agency.

Additionally, NGN would welcome confirmation early in the process on the specific credit rating(s) that Ofgem intends to target in RIIO-3.

Proposal 2 relating to the dividend lock-up trigger

It is NGN's understanding that this proposal is intended to prevent extreme scenarios whereby a hypothetical Licensee may wish to continue paying distributions to its shareholders when its credit quality deteriorates beyond certain thresholds (a credit rating of BBB- with a negative watch/outlook or 80% regulatory gearing), thus allegedly putting at risk its financial resilience and customer interests. We understand why Ofgem may in principle want to introduce measures to protect consumers from the effects of such extreme scenarios if existing protections are insufficient.

NGN has demonstrable evidence of its financial prudence since incorporation and will continue to pursue a rational and prudent financial strategy throughout RIIO-3 and beyond, acting in customers' interests in all respects of our activity, including when it comes to dividends. We would therefore consider that existing protections in the licence work and, to our knowledge, there has not been evidence of a potential financial resilience issue in the industry. For these reasons, we would see it as very unlikely that NGN will find itself subject to any of the two dividend lock-up trigger events.

However, this proposal should be considered in the context that Licensees' ability to increase leverage is already directly restricted through their respective bank covenants and also implicitly constrained via the tax clawback trigger mechanism, which removes any incentive to over-leverage by clawing back the tax benefit a Licensee is assessed to have obtained as a result of gearing levels and interest costs that are higher than assumed.

The fundamental aim of regulation is to protect consumers. Targeted regulation is key to ensuring that regulation remains efficient and effective ("*We regulate only where necessary to protect consumers' interests and we carefully consider whether any regulatory requirement we propose is proportionate*"[132]) and so whilst in reality, the proposal would be unlikely to affect NGN directly, we are concerned about the risk of wider implications and unintended consequences when considering the signal that it may send to investors and the market. The introduction of new licence conditions should only be pursued where the behaviour of Licensees needs correcting, yet to our knowledge, there has been no evidence to suggest that GDNs' financial structures and behaviours would not be able to avoid or cope with, and recover from, disruption (whether in the markets or internally). Investability is key to achieving the UK Government's and Ofgem's Net Zero targets and there is a risk that the introduction of this measure as a new Licence condition could undermine the valued perception of regulatory stability and predictability by regulating more than where it is necessary.

Market sentiment is very important to the Cost of Equity and Cost of Debt and the introduction of this Licence condition – absent any evidence that it is required in the GDN sector – has the potential to impact upon investors' perception of the gas market's investability which in turn introduces the risk of increasing costs for consumers without tangible incremental benefit.

Proposal 3 relating to amending the Availability of Resources Requirement

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[132] Ofgem Website: https://www.ofgem.gov.uk/about-us/our-role-and-responsibilities#:~:text=We%20work%20to%20protect%20energy,the%20lowest%20cost%20to%20consumers

NGN does not agree with this proposal and believes that Ofgem has not made the case that this is needed in order to bolster or increase Ofgem's confidence about financial resilience in the sector.

Currently, SSC A37 requires, among other things, that each year Licensees provide Ofgem with a Certificate, approved by the Board of Directors, confirming whether it has sufficient financial resources such that it can continue carrying on its business for the following 12 months. Consequently, NGN currently manages its finances to ensure compliance with going concern requirements (in practice, based on a 12-month time horizon considered sufficient by an external auditor), credit rating agency liquidity considerations (typically also a 12-month horizon) and of course the existing Licence provisions (the long-standing 12-month time horizon).

This proposal suggests increasing this requirement to a minimum of 3 years, but potentially to 5 years assuming that the regulatory period does not change in RIIO-3. This is not just far more onerous than the current requirements but is also likely to involve additional costs to consumers. We do not consider that this is necessary, especially in the context of Ofgem assessing and having visibility of GDNs' resources and business plans, on a five-yearly basis, when it sets the price controls.

We are particularly concerned about the cost implications that the introduction of this obligation could result in, given it may require earlier pre-financing by a Licensee adopting a prudent approach. For a Licensee to certify that it has sufficient financial resources to cover a period greater than twelve months (whether that be the entire price control period or a minimum of three years ahead) it would need to have fully committed funding in place to cover all expected obligations in that period, with headroom.

If the additional funding requirement were met through a larger bank facility, that would incur considerable additional costs by way of up-front fees and ongoing commitment fees. It is also unusual for the maturity of such credit facilities in the current environment to extend beyond three years, other than by way of extension options whose acceptance by lenders is not guaranteed, hence it is questionable whether such an arrangement would enable a Licensee's directors to give the necessary assurances.

Meeting the funding requirement with newly raised long-term debt would incur considerable carry costs, given that the funds would need to be in place up to five years before they are going to be utilised. Given that the Availability of Resources certification is given annually, this would be a rolling feature.

Fulfilling this proposed requirement is likely to be particularly challenging where there is a need to pre-finance across two price control periods. For example, it would be extremely difficult to forecast with any accuracy what level of financing would likely be required before the regulatory framework and its key parameters have been confirmed by Ofgem. Securing finance for a minimum of 3 years ahead of these circumstances where the upcoming regulatory framework is still under consideration results in Licensees being put into a situation where they are forecasting into periods of the unknown. This inherently results in forecasts being based on less certain estimates. Should it even be possible to achieve external audit sign-off in this case, it raises the question of whether the outcome is achieving its intended policy objective. The uncertainty would very likely result in more costly financing given the risk involved and we do not see how this could be seen as being in the public interest.

In addition, and without prejudice to our general view that the water sector is not directly comparable to gas distribution, we also note that in the water sector, while Ofwat introduced new financial resilience licence conditions in March 2023 (for reasons which do not appear to apply in the GD sector), it maintained the time period for the board certification of the sufficiency of financial and management resources to carry on the business as 12 months. As we highlighted above, a longer certification period cannot be assumed to be cost-free and hence should be subject to a detailed impact assessment, weighing any incremental benefits against the costs for the consumers, which has to be separately carried out by Ofgem should it decide to adopt changes in this regard.

We consider that there are more proportionate ways in which Ofgem may be better able to meet its objectives whilst also minimising adverse consequences on both Licensees and consumers. This may be achieved in the following way:

- Ofgem already collects significant information from Licensees through the RFPR reporting, consequently, there is a natural opportunity to streamline this reporting and rethink how this information is utilised. The current reporting template is extensive and very granular, where too much detail may stand in the way of efficient review. Were Ofgem to undertake a review of the RFPR to simplify the information submitted, ensuring that it can be targeted towards meeting a specific objective, it would likely result in a more efficient process which provides meaningful results that can be analysed quickly and easily.
- Certifying the availability of resources should continue only for twelve months. However, should Ofgem have a material concern in relation to a particular Licensee, it could request them to provide information on the subsequent 24 months (or to the end of the price control) in an agreed format/ template.
- In this case, the "agreed assumptions" (as alluded to in the description of the measure) will have to include information about potential future funding within the forecast period that is not yet committed. In case of a material concern about a Licensee's financial position, this could take the form of a representation that the anticipated funding would not be expected to cause covenants to be breached or lead to a credit rating downgrade.

A combination of some or all of the above would be more likely to fulfil Ofgem's policy intent, with fewer adverse impacts on Licensees, and limiting incremental costs which ultimately would affect end customers. Should Ofgem wish to consider these further, NGN would be happy to engage in a meaningful way outside of this SSMC consultation.

Overall, we consider that the cost implications of this third proposal could be significant (including, ultimately, for customers) and are likely to bring little to no countervailing benefit to consumers. On the basis that broadly the same “*early warning*” and mitigating measures already exist under SSC A38 (in terms of the Financial Resilience Reports) introduction of this measure is unlikely to be in the best interest of consumers.

FQ16. Are there better ways to protect against excessive leverage and financial risks, in particular leverage via acquisition finance, by utilising existing powers rather than imposing new requirements in the licence?

It is not necessary to broaden existing powers or introduce new ones to protect against excessive leverage because any risk surrounding the ability to service MidCo/HoldCo debt lies with the shareholders of the borrowing company.

We refer to our responses to FQ15 and FQ17 of this consultation which clearly evidence that there are already significant protections in place with regard to ensuring financial resilience, including requirements and incentives regulating and restricting where appropriate gearing levels as well as dividend payments. Should debt financing increase to unsustainable levels, the Licensee in question would risk breaching a number of existing Licence conditions, including SSC 37. At the very least, the credit rating of the GDN in question would be affected. This in turn would trigger SSC A38, which requires the Licensee to promptly notify Ofgem and subsequently provide very comprehensive Financial Resilience Reports, should a negative rating action occur as a result of the deterioration of its credit quality beyond defined thresholds.

FQ17. For the SSMC we have not proposed dividend controls or dividend policy requirements. How should we think about protections to ensure that leverage at MidCo and/or HoldCo does not become disproportionately influential in decision making at the licensee with the potential for negative outcomes for consumers?

We welcome that Ofgem has not proposed dividend controls or dividend policy requirements, presumably being conscious of the potential harm to consumers such measures may cause if introduced without due consideration. As a general point, imposing dividend controls in the licence beyond existing obligations would require a proper impact assessment of unintended consequences against the likely benefits. Given the potential impact on investability, cost of capital and investor expected returns, any such policy decisions cannot be taken lightly.

We consider that Ofgem should continue focusing its attention and regulatory controls on the regulated business and its debt structure. The existing requirement for a Licensee to use reasonable endeavours to maintain an investment grade credit rating or ratings should ensure consumers are not negatively affected by Midco or Holdco leverage. The risks around the ability to service MidCo/HoldCo debt are naturally borne by the debt providers, and it is for the shareholders of the MidCo/HoldCo to manage those risks, so that the Licensee company can concentrate on operational performance and fulfilling an extensive set of the existing Licence requirements.

Ofgem's protections in this area are already broad and comprehensive: for example, SSC A37 stipulates that "*the directors of the Licensee must not declare or recommend a dividend, and the Licensee must not make any other form of distribution*" before certifying to Ofgem that the Licensee is in compliance with all of the obligations imposed on it by SSC A26 (Provision of Information to the Authority), SSC A36 (Restriction on Activity and Financial Ring Fencing), SSC A37 (Availability of Resources), StC 45 (Undertaking from Ultimate Controller), SSC A38 (Credit Rating of the Licensee and resulting obligations) and SSC A39 (Indebtedness); and that making of a distribution, will not cause the Licensee to be in breach to a material extent of any of those obligations in the future.

Moreover, there is a risk of future under-investment if measures to restrict gearing are over-zealous, disproportionately interventionist, and impinge on network companies' ability to pay dividends that are justified in the context of risk-taking and performance.

We consider that, provided that the current protections which exist around financial resilience remain in place and are properly monitored and enforced by Ofgem, the exact proportions of MidCo and HoldCo debt have no bearing on consumers.

FQ18. Is there merit in amending the RFPR RIGs to include requirements for Licensees to undertake stress-testing, and to provide the results to Ofgem, as in the Retail sector and as the Prudential Regulatory Authority/Bank of England does for banks, to test for financial resilience?

Introducing stress testing to an asset-rich business is not necessary and would simply result in additional cost and complexity for both the GDNs and Ofgem, with no real consumer benefit.

This is primarily due to GDNs having a much less variable revenue profile, compared to other industries such as the retail sector or banking as cited in Ofgem's example. In those sectors the business models are associated with large revenue volatilities and in this respect, regular stress testing on some downside scenarios could be of value and hence unsurprisingly being required by the Prudential Regulation Authority. However, for a utility business, significant and unexpected revenue fluctuations are far less likely to happen. In any case, we assume that financeability assessments performed as part of the RIIO-3 Business planning process and prior to the final determinations (as was the case in RIIO-2) would include downside scenario stress-testing in relation to cost overruns, inflation and interest rate volatility, and possible penalties for outcome underdelivery. If necessary, mitigating actions would have to be agreed upon ahead of the price control final settlement.

Moreover, the fact that GDNs have invested billions of pounds into the physical assets deployed within their networks and cannot simply exit the market even in the event of financial distress, means that one cannot realistically compare it to a low asset base retail business. Finally, Ofgem has the ability to request any information from GDNs at any time, including ad-hoc stress testing, so there is no material need to mandate this further which would create additional costs and burden for GDNs and Ofgem.

Corporation tax

FQ19. Do you agree with our proposal to align the RIIO-3 tax approach with RIIO-2 and RIIO-ED2 including; to maintain Option A - notional allowance with added protections; the approach to capital allowances, and "glide path"?

Yes, we agree with maintaining Option A and its associated approach to capital allowances and the glide path.

At RIIO-2 tax pool allocation rates and tax rates became variable values to enable updates to be incorporated during the price control. Maintaining the current approach is likely to lead to the best outcome for consumers. Having the ability to alter capital allowances in-period minimises the risk of distortion between regulatory tax allowance and actual tax payable. We consider that the introduction of these variable allowances led to a more equitable outcome for consumers and we would support its retention.

In relation to gearing, the glide path was introduced in order to gradually reduce the gearing level from 65% to 60% over the duration of the price control following the change to notional gearing levels from RIIO-2. Given Ofgem has not signalled further changes to notional gearing levels, our current understanding is that there will be no further changes to notional gearing levels within the upcoming regulatory period. We note that the gearing glide path will have reached 60% by the beginning of RIIO-3. It is therefore unclear why the glide path will be relevant throughout RIIO-3. We would be grateful if Ofgem could clarify its intentions in this area.

That said, if the gearing levels are altered in the future, we consider that doing so gradually on a glide path basis is important to reduce the impact on both networks and consumers by allowing time for GDNs to adjust.

FQ20. Do you agree with the proposed revision to tax clawback methodology?

Yes, we agree with the proposal as things stand today. Our understanding is that Ofgem is proposing that the regulatory definition of net debt be revised to include cumulative accretion on inflation-linked derivatives, net of paydown, to fully capture the components of gearing where there are no substantive economic reasons to deviate between the two. We have already raised our concerns in this area within our annual RFPR reporting, where we highlighted the need to include accumulated swap accretion within debt for the purpose of calculating gearing ratios.

There are two reasons why we consider that this is the correct approach: firstly, it ensures consistency with credit rating methodologies for calculating debt-related credit metrics. Secondly, failing to include the ongoing accretion amount as part of regulatory debt would bring about a cliff edge at the maturity of Index Linked (I-L) derivatives as the accretion is paid down and new debt is raised to fund the payment.

In NGN's financial statements accumulated accretion, although separately disclosed, is included in swap creditors rather than in debt. Economically, however, it is a debt-like obligation, requiring full settlement at maturity (whereas interest rate swap fair values will be nil at maturity). When the I-L swaps mature and accretion falls due for payment, NGN will have to arrange funding to make the payments, thereby increasing debt and gearing and this clearly has implications from a planning and financing point of view. For these reasons, we consider that amending the regulatory definition of net debt to include cumulative accretion is methodologically the correct approach.

Regulatory depreciation and economic asset lives

FQ21. GD & GT: assuming re-openers are available and there is no adjustment to the allowed WACC, how should regulatory depreciation be used to address the uncertainty around the future path for gas and perceived asset stranding risk?

Contrary to the premise of the question, NGN does not consider a re-opener to be necessary (as explained in our answer to FQ23) and we think an adjustment to WACC is necessary (as explained in the Overview as well as our answer to FQs 1 - 9). We have responded to this question without prejudice to this view.

When considering this issue for RIIO-3, it is essential that Ofgem avoids any adverse impact on incentives for the GD sector to continue investing to maintain safe, reliable and resilient operations at all times, to enhance service performance, and to continue investing to drive forward innovation. All of this is to the benefit of customers.

As part of this, when discussing its policy in relation to RAV recovery, Ofgem should take care to avoid adversely affecting investor views on the GD sector. Investors are paying close attention to recent developments, and the way Ofgem frames these issues affects investors' perception of risk. In particular, Ofgem must take care to avoid language that suggests it believes the gas sector is in terminal decline.

It is also essential that any change in Ofgem's approach to RAV recovery does not lead to underfunding the licensees in other areas (e.g. allowances for Capex, Repex, WACC etc). Ofgem is contemplating changes that would result in higher cashflows in GD3 – but any assessment of financeability and investability must ensure that it 'sees through' any policy changes that re-profile cash between current and future customers (i.e. to ensure the underlying and long-term financeability and investability of the sector).

We agree with Ofgem that "*the status quo depreciation charge is unsustainable for ensuring all invested RAV is repaid by 2050.*" and that *"This raises the question of who should pay for the gap."*[133] [i.e. unrecovered RAV]. We don't think it is appropriate to assume that the risk can reside with investors without adequate compensation in RIIO-3 as it would indeed "*undermine regulatory stability and predictability and is likely not in the consumer interest*"[134]. That said, there are clearly plausible FES scenarios that still entail long-term use of the gas distribution grid as essential national infrastructure. This may be either for ongoing use of natural gas (e.g. in the Falling Short scenario) and/or for possible repurposed uses.

There remains material and genuine uncertainty around the future use of gas distribution networks. In its second National Infrastructure Assessment, published in October, the National Infrastructure Commission concluded that *"there is no public policy case for*

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133 RIIO-3 SSMC Finance Annex, para 8.37

134 Ibid

hydrogen to be used to heat individual buildings. It should be ruled out as an option to enable an exclusive focus on switching to electrified heat."[135] FES scenarios such as Customer Transformation and Leading the Way show a very dramatic reduction in the use of gas (whether natural gas or hydrogen) amongst the bulk of our direct customer base in the next two decades. On the other hand, it is clear that heat pump uptake is slow (and far behind the target of 600,000 installations per year). In addition, recent developments in offshore wind and nuclear call into question the deliverability of high electrification scenarios. Substantial policy uncertainty prevails – for example, given the delays in bans on gas boiler installation in new homes and sales of new internal combustion engine cars; and changes being considered for the clean heat market mechanism (recently branded as a "boiler tax"). DESNZ's Hydrogen for Domestic Heat decision is not due until 2026.

Given this uncertainty, Ofgem should not build its policy for RAV recovery based solely on a fixed assumption that one particular scenario is the most likely outcome. The policy for RAV recovery should reflect a balanced view of possible long-term outcomes. This is in the customer interest to avoid a situation when customers today could end up over-paying (relative to future customers) if RAV recovery is substantially accelerated. Any change to the RAV recovery policy must also balance questions of affordability/acceptance for today's customers and the need to ensure ongoing financeability and investability for the sector.

Ofgem has indicated that it might be considering a very substantial RAV recovery acceleration through what it has described as *"`smoothing' the profile of consumer unit charges between the RIIO-3 and the assumed de-energisation point to promote fairness between current and future consumers."*[136] Specifically, Ofgem says it has *"indicatively modelled a scenario that would 'smooth' the depreciation of the Gas Distribution RAV over the existing and future customer base. In this example we have sought to profile a flat allowed depreciation charge (in real 18/19 CPIH prices) according to gas demand per kWh."*[137] Ofgem says this indicative scenario would add £35 - £43 to customer bills today.[138]

Ofgem's suggestion of a flat depreciation charge would require a fundamental change to the regulatory model – specifically, it would require Ofgem to base today's customer charges on long-term projections of gas demand volumes or projected customer numbers and ongoing investment to 2050; and it would require Ofgem to set a target closing RAV in 2050 factoring in possible re-purposing value which, as it stands today, is difficult to quantify. These requirements make the proposed smoothed charge complex and potentially arbitrary – introducing more rather than less uncertainty and possible volatility.

In addition, Ofgem's indicative modelling understates the possible GD3 bill impact of its proposal. This is primarily because Ofgem's modelling does not include post-RIIO-2

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[135] https://nic.org.uk/studies-reports/national-infrastructure-assessment/second-nia/#tab-foreword

[136] RIIO-3 SSMC Finance Annex, para 8.39

[137] RIIO-3 SSMC Finance Annex, para 8.25

[138] RIIO-3 SSMC Finance Annex, para 8.26

investment.[139] We anticipate that once a conservative assumption for business-as-usual ongoing investment from RIIO-3 onwards is factored in, Ofgem's proposed "*smoothed*" depreciation charge would result in much more significant GD3 bill increases compared with the £43 quoted in the RIIO-3 SSMC Finance Annex.

In addition, Ofgem has stated the purpose of a smoothed charge would be to avoid "*dramatic increases in the customer unit charge*".[140] However, a smoothed depreciation approach would not prevent unsustainable bill increases in the medium and long term in low-demand scenarios. This is because even if depreciation charge were smoothed across multiple price controls, the remaining revenue building blocks still drive very material bill increases in a falling gas demand scenario. We note that if/when demand starts to fall, Totex and other costs do not scale 1-to-1 with demand – there will be material ongoing operating costs for running the businesses even as demand and customer numbers fall. Even those (load-related) costs that are likely to fall with demand more proportionately are likely to do so with a significant lag (and not necessarily in direct proportion to demand reduction).

Further complexity associated with Ofgem's '*smoothed depreciation'* proposal would arise if future decommissioning costs need to be factored in; and if the GDNs are expected to bear any transitional costs associated with switching to alternative heating systems.[141]

We also note that with higher interest rates and uncertain macroeconomic outlook, increasing legislative workload requirements, and the moderate decline in volumes envisaged under some FES scenarios from the start of RIIO-3, customer bills are likely to be rising in RIIO-3 even under the status quo depreciation profile. An acceleration of depreciation will exacerbate this problem today and could impact future customers even more – particularly vulnerable ones who may not be able to switch – due to feedback loops.

As a result of the above issues, if Ofgem concludes that it is in the best interests of customers to accept near-term bill increases in order to further accelerate the recovery of RAV (we would welcome clarity on this question from Ofgem as soon as possible), we would advise that Ofgem adopts a more simple and transparent approach than the contemplated '*smoothed depreciation'*. Much of the complexity identified above can be avoided by adopting a straightforward change to asset lives or the depreciation profile. This would have

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[139] We also note that Ofgem's illustrative spreadsheet contained other errors. For example, Cell E22 in tab 'Smoothing scenario bill impact' shows total amount needed to depreciate the RAV existing at the end of RIIO-2 fully, not the amount that would be depreciated by 2050 under status quo depreciation policy. As such, cell G22 double-counts the closing RAV in 2050. Moreover, the illustrative bill impact calculation does not account for the fact that allowed return on RAV would need to be recalculated in each year in line with the new smoothed depreciation schedule.

[140] RIIO-3 SSMC Finance Annex, para 8.25

[141] Estimates from ARUP suggest that decommissioning costs for gas distribution companies in Consumer Transformation scenario could amount to £6.9bn, with customer disconnection costs adding a further £28.5bn, and repurposing costs adding £2.9bn. Under System Transformation scenario, domestic customer transitioning and repurposing of the distribution grid is estimated to cost £14.7bn. ARUP (October 2023), "Future of Great Britain's Gas Networks", p. 72, 76, 110, 120, 155.

the benefit of retaining the fundamental structure of the existing regulatory framework. Ofgem should also recognise that the currently high levels of uncertainty will ultimately resolve over time, meaning it will always have the option to course-correct at future price controls as more information emerges.

Importantly, we note that any adjustment to regulatory depreciation which Ofgem chooses to implement can only ever partially mitigate the stranding risk we face. Stranding risk cannot be entirely removed (or "*addressed*" as Ofgem suggests) because scenario uncertainty will remain and the pace of technological change, policy change and customer behaviour change are all highly uncertain.

In light of this, we agree with Ofgem that one avenue for closing the gap would be via mechanisms outside of the standard RIIO framework, originally designed when full utilization of the gas networks in perpetuity was not in question. Indeed, as Oxera notes "*A number of solutions are available to address the asset stranding risk. Some of these are outside of the regulatory framework and generally within the remit of the government, and sometimes they require legislation to be passed in order to be implemented*".[142] For example, government guarantees to compensate for stranding risk have been provided to Hinkley Point C investors in the UK; and in Germany, the government has committed to compensating the majority of the deficit between the expected and actual revenues.[143]

As Ofgem also rightly notes, *"this is clearly dependent upon future government policy".* [144] In our view, it is highly likely that some form of socialisation and/or other Government (i.e. non-RIIO) mechanisms are going to be required. We are willing to support Ofgem in working with the Government to develop such mechanisms. We note that this discussion must also aim to achieve clarity around liability for decommissioning costs and the risks and uncertainty for investors arising from this (e.g. financeability and legal risks).

We also understand that, as Ofgem states: *"while recognising that government policy can change, Ofgem bases decisions on the current stated position and how that flows into Ofgem's remit".*[145] Our assumption is that a binding Government commitment in this area is unlikely to be established in time for RIIO-3. Absent Government underwriting of RAV or other legislative commitment to RAV recovery, it is clear that Ofgem will need to compensate the stranding risk based on the facts today. The reduction of asset lives and/or further acceleration of the depreciation profile could help mitigate this risk, but depreciation policy alone cannot remove the stranding risk faced by investors today.

Therefore, the asymmetric stranding risk that investors will continue to bear must also be compensated, as discussed in the Overview and our response to FQs 1 - 9. We agree with Oxera that: "*a cost of capital uplift (or a specific ex ante allowance) aims at remunerating the*

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142 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.32

143 Oxera (March 2024), "Risks and investability of the GB gas distribution sector", p.32.

144 RIIO-3 SSMC Finance Annex, para 8.37

145 RIIO-3 SSMC Finance Annex, para 8.38

networks for the residual risk that they still bear, accounting for the depreciation policy changes that are implemented. In particular, the scale of the cost of capital uplift (or ex ante allowance) can also depend on the adequacy of other policy changes that are implemented by regulators to mitigate the asset stranding risk."[146].

FQ22. GD & GT: what long-term path should regulatory depreciation aim to follow between 2026 and the assumed de-energisation point to promote fairness for current and future consumers? What unit metrics should this be based on? Is this resilient to the various scenarios under FES 2023?

As explained above in response to FQ21, Ofgem's proposal to '*smooth'* depreciation charges does not fully deliver Ofgem's intended outcome of avoiding large bill increases. In addition, the proposal would create a complex system which is a material departure from the existing regulatory framework.

One (of several) complexities that arise is that smoothing depreciation charges requires making a choice over the unit metric to base the smoothing calculation on. Addressing this question would not be necessary if Ofgem limited itself to simpler and more transparent modifications to asset lives or the depreciation profile.

If Ofgem nevertheless wants to pursue a complex '*flat depreciation'* proposal, Ofgem has asked if it is more appropriate to smooth depreciation across a measure of volumes (i.e. GWh) or a measure of customer numbers[147]. The following considerations are relevant.

- Spreading costs by customer numbers effectively charges each individual customer a fixed amount of the incremental cost recovery burden. Arguably this is a more appropriate means of spreading existing asset recovery cost in principle as customer numbers are a more stable parameter less prone to temporary fluctuations. However, it would raise fairness questions as low-consumption consumers (who tend to be more vulnerable) would effectively be asked to pay as much as high-volume consumers. The issues here therefore bear some resemblance to the debate around the mix between standing charges and volumetric charges for domestic customers.
- Another issue that Ofgem might wish to consider when making this choice is the degree of credibility and reliability of the forecasts it chooses to use. Ofgem should seek to evaluate whether the projections of customer numbers or other metrics appear to be more reliable and accurate in the long term.

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146 Oxera (March 2024). "Risks and investability of the GB gas distribution sector", p. 34, para 4.8.

147 RIIO-3 SSMC Finance Annex, para 8.27.

- We note that Ofgem will also need to consider whether and how its smoothing calculation should be applied to industrial and commercial customers. This will add another layer of complexity to the '*smoothed depreciation'* proposal.

We would welcome a clarification from Ofgem on its intended depreciation policy and we are happy to continue conversations on the appropriate measure to be used to smooth the charges should Ofgem decide to proceed with that.

FQ23. GD & GT: assuming there is a relevant gas reopener for government policy, is there a need to reopen regulatory depreciation policy intra-period?

As noted in our response to FQ21, it is essential that any change in Ofgem's RAV recovery policy does not lead to underfunding the licensees in other areas (e.g. Capex, Repex, WACC allowances). Subject to this requirement, our view is that there is a benefit in making a decision at the beginning of RIIO-3, rather than using a re-opener for regulatory depreciation.

There is a wide range of policy developments that could be considered a 'trigger' for a re-opener on depreciation policy. This is because any net zero policy, from heat pump targets to DESNZ's Hydrogen for Heat Decision, could bring some information about the future of gas distribution networks. Any re-opener would have to be clear in terms of what Government policy decisions could be considered a trigger event.

We assume, however, that Ofgem's primary concern is the Hydrogen for Heat Decision, currently expected in 2026. Due to timelines of regulatory processes, any re-opener triggered by this decision will likely only apply for (at most) the last two years of RIIO-3. This is unlikely to bring large benefits relative to taking a decision at the start of RIIO-4. However, such a re-opener would introduce incremental regulatory resource burden, complexity and risk. These additional costs must be weighed against the (likely relatively small) benefits for customers.

This position is further reinforced by uncertainty about the precise timing and form of the Government decision, and therefore the degree to which it will actually clarify the long-term scenario that gas networks will face. Our preference is therefore for Ofgem to take a decision on the RAV recovery policy in RIIO-3, on the assumption that this could be re-visited in RIIO-4.

FQ24. GD & GT: what considerations are raised by asset repurposing and how might these affect the decisions to be made on regulatory depreciation policy? What guidance is sought for the SSMD so that licensees have sufficient clarity for their business plans?

Repurposing is clearly a significant possibility for the long-term future. Repurposing could substantially benefit natural gas customers, by mitigating stranding risk and avoiding decommissioning costs. Ofgem's RIIO-3 policies should therefore aim to support (and be consistent with) enabling re-purposing to happen, and avoid creating undue barriers to this.

DESNZ is currently developing its Hydrogen Transport Business Model (HTBM) design, with a progress update expected by Q2 this year. DESNZ has also set out its initial view of a Hydrogen Networks Pathway. An important part of the HTBM design will be to establish a methodology by which asset value is transferred into the HTBM if and when assets are repurposed. It is essential that Ofgem and DESNZ co-ordinate on developing this methodology.

However, DESNZ's HTBM update is not expected to materialise before SSMD. It is therefore plausible that some adjustment to the RIIO-3 policy may be needed in light of this, and Ofgem should recognise this in planning the remainder of the RIIO-3 process.

In discussing the repurposing question, Ofgem stated that *"Investors in the residual RAV would be made whole by the purchaser of the RAV, thereby mitigating asset stranding risk."*[148] There is no clear basis on which Ofgem can assume that investors will be "*made whole*" in this way and, absent clear Government policy to the contrary, it certainly should not be presumed that stranding risk can be dismissed on the basis of this presumption.

In terms of guidance sought in the SSMD, more clarity on Ofgem's intended RAV recovery policy for RIIO-3 is crucial for assessing the financeability of our business plan.

FQ25. ET: do stakeholders consider there to be a need for amending the existing RIIO-ET2 asset life and/or profile assumptions, on either a company-specific or sector basis? If so, please set out your evidence base and potential consumer benefits and costs of changing the existing methodology.

N/A

FQ26. If a 'semi-nominal' cost of debt and WACC approach were to be adopted which results in an acceleration of cashflows, would this impact your responses to any of the questions above?

We understand that Ofgem is considering adopting a '*semi-nominal'* cost of debt and WACC approach to address an issue which Ofgem perceives regarding the regulatory treatment of inflation. Stranding risk is a completely different problem, where asset lives and depreciation profile can be part of the regulatory response, the resolution of which should be considered on its own merits. This would reflect good regulatory principles of adopting decisions and policies which are targeted at, and consistent with, the apparent issue Ofgem is seeking to address. Therefore, any decision Ofgem adopts on the semi-nominal cost of debt should not in principle affect its views on the correct depreciation policy.

[148] RIIO-3 SSMC Finance Annex, para 8.28

As highlighted in our response to FQ21, any decision should meet the critical constraint that the licensees have sufficient funds to cover their necessary and efficient costs (e.g. allowances for Capex, Repex, WACC etc). Subject to this test, Ofgem's policy decisions in the round must deliver acceptable bill impacts for current and future customers. The merits of the options being considered should be evaluated independently but also subject to these in-the-round tests – it would then be for Ofgem to assess if the bill impacts associated with adopting both a semi-nominal cost of debt and accelerated depreciation would be sensible, acceptable for customers, and reflect the benefits accruing to customers arising from these policies. For GDNs, these in-the-round tests have to be conducted over a longer term than the RIIO-3 period of 5 years, as discussed in response to FQ13.

Return Adjustment Mechanisms (RAMs)

FQ27. Do stakeholders have views or evidence as to why RAMs should or should not continue?

Ofgem states that: *"The purpose of RAMs is to provide protection to consumers and investors in the event that network company returns are significantly higher or lower than anticipated at the time of setting the price control."*[149] As stated within our response to the RIIO-2 Draft Determinations, an ex-post Return Adjustment Mechanism (RAM) can be harmful to consumers in principle if it affects Licensees' incentives and undermines investor confidence.

A RAM, as an extra failsafe measure, should be unnecessary with a correctly calibrated price control. There are several measures already contained within the regulatory framework which are designed to protect consumers including the Totex Incentive Mechanism (TIM), the Business Planning Incentive (BPI), uncertainty mechanisms (UMs), Output Delivery Incentives (ODIs), and Price Control Deliverables (PCDs). These are all intended to ensure that consumers are receiving value for money and are protected from uncertainty.

The RAMs risk dampening Licensees' incentives to make further efficiencies beyond the threshold, by effectively halving the returns beyond the primary threshold and almost entirely removing them beyond the second. The converse is true for underperformance beyond the thresholds, which means that the higher the level of Totex overspend or ODI underdelivery, the higher the cost customers will have to bear. We note within our responses to OVQ32 to OVQ34 that incentives provided under the RIIO-2 framework are not commensurate with the value that NGN delivers as a frontier company (which benefits all UK customers) and may even discourage laggard companies from catching up. The RAMs risk further diluting the overall incentive framework and could contribute to driving the wrong behaviour to the detriment of consumers in RIIO-3.

In our view, the risk of reducing Licensees' incentives to maximise efficiency (which should be at the centre of an effective regulatory regime), combined with the complexity that RAMs add to the regulatory framework, can harm consumers over the longer term.

FQ28. Do stakeholders have views or evidence as to whether the RAMs methodology should be amended, such as recalibrating the threshold or rates or including financial performance?

Without prejudice to our views on RAMs as outlined above, should Ofgem determine that the RAMs will remain for the upcoming regulatory period, there are a number of important considerations in their calibration.

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[149] RIIO-3 SSMC Finance Annex, para 9.1

In principle where RAMs exist, they should remain symmetrical to ensure that both consumers and Licensees are protected from unexpected deviations in costs or other uncertainties over the regulatory period.

In terms of whether financial performance should be included within the RAMs, we would first refer to Ofgem's stated principle, with which we fully agree, that "*In setting allowed returns based on a notional capital structure, regulators allow companies the flexibility to make decisions on capital structure that are appropriate for each individual business (subject to financial resilience requirements). This approach ensures that management and owners remain responsible for the risks and rewards of the actual capital structure and financing decisions, and that the outcome of these independent decisions does not impact consumers*."[150] In short, financial performance should not be included within RAMs. This will create material additional complexity and also increase the risks of distorting incentives across the whole price control (as outlined in FQ27).

Notwithstanding the fact that Licensees are yet to see how RAMs work in practice given that they would be calculated over the entire GD2 period as part of the GD2 close-out process, we currently see no reason to deviate from the current thresholds that are in place. On balance, we would suggest that if RAMs were to remain, the thresholds should also remain at the status quo levels to minimise the risk of unintended consequences on Licensees and consumers. As per our response to the RIIO-2 Draft Determinations, we consider that it is vital that any RAMs that exist should not reduce returns below the allowed Cost of Debt; otherwise, Licensees become at risk of being unable to meet their licence obligations and being unable to service debt interest payments.

FQ29. Do stakeholders have views or evidence as to whether there should be separate RAMs for 'BAU' parts of the business and specific programmes, such as ASTI?

Currently, the RAMs are based on combined Totex and ODI performance for all operational outputs combined. There is little merit in separating RAMs into Business as Usual (BAU) activities and other specific programmes for GDNs, given the Accelerated Strategic Transmission Investment (ASTI) only relates to Transmission. The additional reporting complexity would not bring any additional consumer benefits. Furthermore, separate RAMs for separate activities would add additional complexity and further increase the risk of distorted incentives outlined in FQ27. Arguably, those incentives which have individual caps/collars already effectively have an incentive-specific RAM in place, so this additional proposal would also be duplicative.

Therefore, should Ofgem decide to retain the RAMs as an "*extra*" failsafe regulatory measure, we consider that the current position for GDNs should be retained.

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[150] RIIO-3 SSMC Finance Annex, para 4.7

Other finance issues

FQ30. Is there a case for altering the capitalisation rate modelling approach between sectors (eg removing the multiple bucket approach for GD)?

No, we don't perceive a particular problem with the current multiple-bucket approach, hence consider that it can be retained for GD3. Having two capitalisation rates has worked well. The profile of investment carried out is different between bucket one and bucket two (with bucket two generally consisting of re-openers).

Ofgem notes that the logic for introducing the separate capitalisation rates was to reflect the likely higher Capex spend within the second bucket, which has indeed been observed by NGN to date.

With a likely move towards increased digitisation in RIIO-3 and beyond and a possible increase in the magnitude of other re-openers, retaining the multiple bucket approach provides Licensees with better transparency and much-needed flexibility in that changing landscape.

Our view is that retaining the multiple bucket approach is important to ensure that reported capitalisation values most accurately reflect operational practices, particularly at a time when there is growing uncertainty for GDNs and the potential for the increased use of re-openers in the next price control period.

FQ31. What are your views on retaining an ex-ante capitalisation rate for allowed totex, but reporting an outturn capitalisation rate for the purpose of calculating the totex incentive mechanism?

Within our response to the RIIO-2 SSMC – Finance Annex, NGN was supportive of setting capitalisation rates on an ex-ante basis. To date, this approach has worked well and as a result, we do not see a need for change.

We maintain that setting capitalisation rates on an ex-ante basis is likely to result in a better outcome for consumers, given it ensures that networks are ambivalent to whether they implement Opex or Capex solutions. From a Licensee perspective, setting the capitalisation rates ex-ante provides more predictable revenue, which is clearly important from a budgeting and consumer pricing perspective.

We note that Ofgem's preference for RIIO-3 would be for networks to report an outturn capitalisation rate for overall actual Totex, then calculate the TIM on fast and slow money pots, rather than by bucket. As outlined in response to FQ30, we don't see a problem with the existing mechanism and would welcome further engagement with Ofgem to better understand the perceived benefits of implementing this change.

FQ32. Are there any reasons why the RIIO-3 approach to directly remunerated services should differ from RIIO-2?

Currently, the costs associated with Directly Remunerated Services (DRS) are not included within Licensee cost allowances to ensure that consumers are not paying for services which Licensees have already been remunerated for. The logic for this is clear and remains relevant as we move forward into the next price control.

FQ33. Do stakeholders have any reasons or evidence to suggest more directly remunerated service categories are necessary?

The categories which currently exist and are applicable to GDNs include:

- DRS1. Connection Services
- DRS2. Diversionary works under an obligation
- DRS3. Works required by any alteration of premises
- DRS6. Emergency Services
- DRS8. Independent System operation
- DRS9. Network Innovation Funding
- DRS15. Miscellaneous

These remain appropriate at this time and are likely to be reflective of categories required in the upcoming price control.

FQ34. Do stakeholders have views or evidence in support of or objection to treating all asset disposals as fast money? Would the existing or alternative approaches have greater merit?

Currently, when an asset is disposed of, the cash proceeds are netted off against pre-TIM Totex allowances from the year in which the proceeds occur. To date, this approach has worked well and we don’t consider that the contemplated change would result in significant benefits for consumers. The current rate of asset disposals suggests that for NGN this change is unlikely to cause a material impact, in the business-as-usual scenario. However, we agree with Ofgem that in case of a material increase in the quantum of asset disposals in RIIO-3, treating all asset disposals as fast money could result in a significant revenue and cashflow reduction in a subsequent year, which in turn could have unintended adverse consequences for Licensees' financial resilience. Therefore, we believe that the current approach should be retained.

FQ35. Do stakeholders have views or evidence as to what reporting information should be provided to Ofgem (under the RPFRs or other forms) to ensure objective identifiability of repurposed assets and cost data remains appropriately like-for-like?

The UK Government's upcoming decision on the suitability of hydrogen for heating homes in 2026 is likely to bring this issue to the forefront, given that the decision will directly impact on the scale of asset repurposing activities which could be undertaken by GDNs. It therefore would be preferable to revisit this question after the 2026 decision is announced.

We also note that DESNZ's ongoing development of the Hydrogen Transportation Business Model (HTBM) will also be relevant to this question. DESNZ has signalled it intends to work closely with Ofgem to develop the HTBM over 2024 and 2025, which may well prompt further relevant considerations for data reporting.

FQ36. Do you consider that the existing reporting requirements on executive pay/remuneration, dividends and corporate governance previously introduced for RIIO-2 price controls remain appropriate in helping demonstrate the legitimacy and transparency of company performance?

Yes, the existing Licence conditions and the RIGs on annual RFPR already contain a very comprehensive set of rules and obligations to regulate companies' remuneration, distribution and reporting policies.

For example:

- SSC A37: Availability of Resources requires the Licensee by 31 July each year to give Ofgem a certificate that has been approved by a resolution of the Licensee's board of directors and signed by a director of the Licensee to certify that "*…having taken into account in particular (but without limitation) any dividend or other distribution that might reasonably be expected to be declared or paid by the Licensee*" the Licensee will have sufficient financial resources to carry on the transportation business for a period of 12 months.
- SSC A37 further stipulates that "*the directors of the Licensee must not declare or recommend a dividend, and the Licensee must not make any other form of distribution*" before certifying to Ofgem that the Licensee is in compliance with all of the obligations imposed on it by SSC A26 (Provision of Information to the Authority), SSC A36 (Restriction on Activity and Financial Ring Fencing), SSC A37 (Availability of Resources), StC 45 (Undertaking from Ultimate Controller), SSC A38 (Credit Rating of the Licensee and resulting obligations) and SSC A39 (Indebtedness); and that making of a distribution, will not cause the Licensee to be in breach to a material extent of any of those obligations in the future.

Moreover, there are indirect tools and mechanisms within the price control framework, which incentivise energy networks to maintain their capital structures in line with Ofgem's notional assumptions. For example, there is the Tax clawback adjustment, which takes effect if a Licensee's actual gearing is greater than the notional gearing level, with any tax benefit derived from its higher tax-deductible interest costs being automatically clawed back reducing the network's tax allowance. This creates a disincentive to introducing highly geared actual company financing structures.

With regard to current reporting, Ofgem highlights that the levels of compliance and completeness against the new reporting requirements for corporate governance were variable across the Licensees[151]. The RIIO-2 RFPR guidance document instructs that *"Licensees must provide an explanation of dividend policies and dividends declared and paid, and how these take account of long-term financial sustainability, including delivery for customers and other stakeholder obligations. This should cover all dividends which Licensees declare, and pay, including those which may be retained within the corporate group, including to service group debt or cover other costs, and not immediately paid up to external shareholders"*.

To date, we have yet to receive our company-specific feedback for our 2022/23 RFPR commentary disclosures. We consider that our reporting was in line with the guidance set out by Ofgem and met all obligations placed upon us. However, as always, we would welcome engagement on this topic should further refinements be required.

It is worth noting that NGN only has 1 executive director and 2 non-executive directors who are paid directly by NGN; the remainder of the Board is remunerated by shareholder companies at no cost to NGN. This is therefore beneficial for NGN customers. Furthermore, information relating to remuneration is already disclosed as part of the statutory accounts and RFPR reporting to Ofgem.

Overall, we consider that there are already comprehensive controls to ensure the legitimacy and transparency of the Licensees' performance, in particular considering the disclosures contained within the RFPR plus its associated commentary, as well as the audited statutory accounts. Any "*variability*" in the quality of reporting can and should be addressed via company-specific feedback by Ofgem following company submissions and/or via RIGS development working groups.

FQ37. Do you have any other suggestions for clarifying or strengthening the reporting requirements with regard to executive pay/remuneration, dividends or corporate governance?

As explained above in our response to FQ36, we consider that the information submitted by NGN as part of the 2022/23 RFPR was comprehensive and met the requirements set out by

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[151] RIIO-3 SSMC – Finance Annex, para 10.34

Ofgem. There is already a wide range of information published or provided directly to Ofgem which should have demonstrated NGN's transparent approach to operating our business and disclosing all the required data.

We do have reservations, however, that should the finer details of dividend and remuneration strategies be made publicly available, then these could be very easily misconstrued due to their complex nature. This issue needs to be considered from the viewpoint of the value that any additional (and potentially market-sensitive) information would bring to customers and stakeholders.

In particular, a dividend or payment in year X does not necessarily relate to performance in year X given business planning and operating activities within the gas distribution sector will necessarily encompass a wide range of long-term strategies and projects, the success of which will be evaluated at various points throughout the lifecycle.

NGN remains committed to meeting all of its regulatory and statutory obligations, though we would highlight that the risk of sharing complex and sensitive information that can be misconstrued needs careful management.

FQ38. Do you have any suggestions on how to improve and future-proof the price control financial model, or use cases it could better support?

NGN welcomes the opportunity to contribute to the Price Control Financial Model (PCFM) development and improvements to the model for RIIO-3.

We broadly support the themes for model improvements outlined by Ofgem[152].

Below are some aspects in relation to PCFM development opportunities that we would like to highlight:

- The PCFM runs only to the end of a price control period; this results in a disconnect between the PCFM and wider business planning. The nature of the gas distribution business requires a longer-term view than 5 years. Even though GDNs undertake their own financial modelling to help them understand the long-term implications that the regulatory decisions will have on their business, it would have been easier if PCFM were to extend beyond the price control 5-year cycle. In addition to improving business planning, there will likely be other benefits generated by extending the PCFM model. Particularly, with regard to carrying over legacy calculations when moving between regulatory periods. Our experience of the transition from GD1 to GD2 highlights just how complex and time-consuming this piece of work is. Updating the formulae to accommodate this transition would, in our view, be beneficial for not only the GDNs inputting into the model but also Ofgem as part of its review. It would also

[152] RIIO-3 SSMC – Finance Annex, para 10.43

make it much more efficient to incorporate close-out adjustments into an "*enduring*" version of the model;

- With the upcoming 2026 decision from the UK Government on the suitability of hydrogen for home heating, it may be worthwhile considering introducing additional modification windows and/or permitting ad hoc changes within regulatory years. However, Ofgem will likely want to consider a materiality threshold, to ensure that only policy changes which are likely to have a material impact on costs or revenue are incorporated;
- Earlier discussions between Ofgem and GDNs presented the idea that some PCFM calculations could be moved into the Licence in algebraic form. We remain of the view that this would likely be challenging and we are not convinced that it would bring consumer benefit;
- Digitisation and automation of PCFM updating is something which has been briefly discussed in the past and we would very much welcome more targeted engagement on this point. At a high level, we would suggest a need for full transparency of all formulae and calculations, along with traceability of each change made to inputs or assumptions. Additionally, should Ofgem be considering departure from Excel, incorporating scripts or using non-Excel software, careful consideration of implementation, maintenance challenges and costs is necessary.
- From an operational point of view when it comes to using the PCFM to inform tariffs, breaking down the Allowed Revenue into Exit, Supplier of Last Resort (SOLR) and Local Distribution Zone (LDZ) is particularly useful, and we would request that this separation be maintained moving forwards.

We note that there are a number of PCFM working groups taking place throughout 2024 and we look forward to engaging with Ofgem on the above and other more detailed topics at those meetings.

FQ39. What are your views on allowing licensees to self-publish the PCFM with their charging statements, rather than relying on an Ofgem publication or direction to determine allowed revenue?

NGN would be supportive of a move towards PCFM self-publication as part of the current Annual Iteration Process (AIP), some aspects of which as it stands now (e.g. multiple dry runs) in practice tend to be both inefficient and labour-intensive for both Licensees and Ofgem. NGN holds itself to account through its rigorous internal assurance and audit processes which would minimise the risk of inadvertent errors or similar issues.

That said, consistency and timely provision of Ofgem-defined input variables such as WACC, inflation and RPEs is key to ensuring this proposal is effective, should it be introduced. For Licensees to ensure a smooth completion of the AIP, the dates at which Ofgem will supply these key inputs should be communicated and agreed upon early in the process, allowing sufficient time for Licensees to calculate the remaining PCFM outputs.

Once Licensees have responsibility for the model, there should be no requirement for multiple '*dry runs*' as is currently the case. However, we understand that Ofgem will likely wish to retain oversight ahead of the final submission. It would likely make the most sense to have this checkpoint towards the end of the process in the interest of efficiency.

The upcoming PCFM working groups would be an ideal place to discuss the practicalities of this proposal in more detail.

FQ40. What are your views on applying a single time value of money in the financial model to all prior year adjustments, based on nominal WACC?

Currently, there are two Time Value of Money (TVOM) rates which apply: a WACC TVOM rate in case of ADJ-type revisions and a CoD proxy rate in the case of the K Correction Factor. This approach is arguably more logical and accurate in trying to mimic a hypothetical network's economic rationale in different scenarios than adopting a single TVOM approach for all adjustments.

Ofgem considers the time value of money to be the "*marginal cost of capital for revenues switched between years during the price control*"[153]. That marginal cost will vary depending on whether the network has more cash than planned for or has to borrow more to cover a cash shortfall:

- A positive adjustment implies a network having received less cash than originally planned, such shortfall having been funded with debt. Applying an interest rate based on marginal borrowing costs would therefore be justified, and
- Conversely, where a negative adjustment is required the implication is that the network has benefited from unexpected additional cash which will have been placed on deposit. In that case, the application of an interest rate based on deposit rates would be fair.

We therefore consider that in theory, there is justification for applying a different rate according to whether the adjustment is positive or negative. The foregoing should only apply to PCFM adjustments that are short-term in nature (i.e. where the cash flows have moved in time versus expectation by no more than two years). We also recognise the additional complexity that such differentiation could bring.

For any adjustments relating to RAV or ODIs (as opposed to short-term revenue over/under-recovery), we consider that WACC would be a more appropriate measure of the time value

153 Ofgem (9th July 2020), RIIO-2 Draft Determinations – Finance Annex, Paragraph 11.56, Available at: https://www.ofgem.gov.uk/publications/riio-2-draft-determinations-transmission-gas-distribution-and-electricity-system-operator

of money given the longer-term implications of the value of RAV at any point in time. These might include instances where a network incurs expenditure or earns a reward which will not be recognised in revenue until later in or after the completion of a price control period.

Notwithstanding the above considerations, we understand Ofgem's motivation to move towards a single TVOM rate proxied by WACC, which would indeed better compensate for delays in funding projects through re-openers, earned incentives, and other values that are uncertain. A single TVOM would also contribute to simplifying the financial modelling.