RIIO-3 Sector Specific Methodology Consultation

National Gas Transmission Response

March 2024

Executive Summary

National Gas Transmission (NGT) is the backbone of Britain's energy system today. We will play a leading role in the transition to a clean energy future that works for every home and business. We own and operate the gas national transmission network, delivering energy to where it is needed in every part of the country. We provide over 35% of the country's energy needs, delivering secure and flexible energy to businesses, power stations and homes. We keep households warm and underpin their quality of life. For business, we fuel growth and innovation. We are looking to the future by developing the hydrogen transmission system of tomorrow.

We have a significant role to play in delivering affordable energy security for the UK throughout the journey to net zero and beyond and we understand the vital role we can play in decarbonising our own system and providing hydrogen solutions for the UK. This will grow GDP, create skilled jobs, and provide export opportunities to meet the economic growth ambition for our country.

We are grateful for the opportunity to be involved in Ofgem's process to develop the regulatory framework for the next price control period. And welcome that Ofgem's focus is on simplifying the RIIO framework in a way that retains the richness of benefits to consumers whilst reducing unnecessary complexity (particularly where that adds cost but little value). Working together, it should be possible to create a streamlined, simplified methodology that supports needed investment, decarbonisation and delivers efficiently for consumers. There are a number of key points which must be given attention in the ongoing development of the sector specific methodology, which we provide some detail on below - you will find more information on each in our detailed responses to the consultation questions.

The gas network will perform a critical role in maintaining the secure energy needs of our nation across the transition and beyond.

It is positive to see recognition that flexibility is needed within the price control to manage uncertainty around the future of gas networks and provide funding to ensure continued secure and resilient gas supplies. The priority for economic regulation needs to be to ensure the right level of investment to maintain the resilience our nation needs from the network. The resilience programme we have been undertaking with Ofgem, DESNZ and NESO will be critical in objectively delivering a resilient gas transmission network to maintain energy security for consumers today and in the future.

As identified through the resilience programme, it is critical that investment is made to mitigate for credible low probability / high impact events where the societal consequences of failure are significant: not investing adequately based on uncertainty around the probability creates significantly more risk and cost than prudently investing to meet peak requirements. In line with the recommendations from the programme we will set out in our RIIO-3 business plan the level of interventions required to maintain risk at the levels experienced at the beginning of RIIO-2. It is critical that the recommendations from the resilience programme are recognised as key drivers in Ofgem's analysis of our business plan.

A prudent approach is required to deliver the common goal of transitioning to net-zero.

The scenarios used to build our business plan are central to establishing what energy supply and demand the natural gas network should be designed for. All Future Energy Scenarios (FES) produced by the NESO are produced to be equally likely to occur and therefore a prudent approach would be to plan the gas network against the scenario where gas remains a viable fuel during the energy transition and for some time beyond. This would ensure the overall energy system, and therefore the supply to consumers, is secure and resilient where the pathway through transition remains uncertain. Across all scenarios demand remains sufficiently high during RIIO-3 to preclude any network decommissioning, therefore the impact on the plan of the choice of scenario is likely to be limited. However, it is still essential that the most appropriate scenario is used as the basis of our planning assumptions to ensure our network continues to perform its critical role in delivering energy security to millions of homes, securing jobs for millions of people and keeping the lights on for a significant proportion of time. For Gas Transmission the most appropriate choice of scenario is FES 2023-Falling Short - which represents the most appropriate scenario trajectory in the short to medium term (10-15 years) whilst still enabling an orderly transition out to 2050. Alongside this, we can present analysis for FES 2023-Leading the Way to identify the impact on specific investments which are most sensitive to changes in scenarios to provide important information, including cost implications, on the impact of the different scenario.

In addition, the design of the regulatory framework has existing and proposed mechanisms that allow for load growth or significant changes that deviate from any reasonable scenario or forecast, including reviews to allow for repurposing of assets for hydrogen or carbon transportation.

It will not be possible for updated analysis based on FES 2024 to be submitted alongside our December 2024 final business plan as the data will not be available in time. We also understand that NESO are currently considering revisions to the approach and output of FES 2024, meaning that any commitment to rerun analysis based on FES 2024 represents a risk due to uncertainties to what such revisions might mean. Given that it is anticipated that the Centralised Strategic Network Plan is to be developed by the NESO in 2026 or later, this will be the appropriate point in time to consider any further updates in the scenario used for gas network planning which uncertainty mechanisms within the RIIO-3 framework should account for.

By optimising repurposing, there is an opportunity to add significant value through close alignment of the regulatory framework and delivery model for natural gas and hydrogen.

We recognise hydrogen is out of scope of the framework decision (as indeed is CCS); however, the repurposing opportunity offered by the natural gas networks means that the framework, and indeed future investment needs of these energy vectors, are inextricably linked. We welcome recognition within the sector specific consultation that it may be appropriate for the RIIO framework to enable funding for some repurposing activities. Timely unlocking of repurposing is essential to deliver lower emissions from industrial clusters in the late 2020s and beyond, a decarbonised power network by 2035, and provide low carbon energy for transport and potentially heat.

Delivery of the hydrogen network will require a carefully considered combination of new and repurposed assets. Agility across the corresponding frameworks is essential to recognise within period changes needed to allow repurposing and seamless approval of the necessary activities and funding. The optimal network solution is likely to require elements of new build and repurposed assets, ahead of the necessary studies it is not possible to distinguish the exact split of requirements or specific allocation of costs. We note the plan to introduce a re-opener to account for potential developments in gas strategic network planning. This must enable the necessary repurposing activity to be taken forward in an agile and flexible manner.

Asset stranding is a risk, however the opportunity to repurpose our network makes it challenging to assess how far mitigation should go in the next price control.

We welcome that this risk has been called out in the sector specific methodology with a view to exploring what measure, if any, should be taken within the RIIO-3 period. Owing to the implications for bill profiles and investor risk perception, options to address lifecycle challenges for natural gas need to be managed carefully and sensitively. Any adjustment to core RAV parameters (asset lives, depreciation methodology and capitalisation rates) will need to satisfy the needs of users and investors both now and in the long term.

A consequence of the need for a core hydrogen network, as supported by the National Infrastructure Commission (NIC) recommendations[1], means that the gas transmission sector is very different to the Gas Distribution sector. The Climate Change Committee indicate a central scenario equivalent to around 3,800 km of pipeline being needed, implying a significant proportion of the natural gas RAV could be repurposed[2].

However, uncertainties in the future pathway for natural gas demand and long-term network investment needs in that context, coupled with the range of possible repurposing outcomes, make it challenging to assess how robustly we should seek to address lifecycle challenges in the next price control. We believe, therefore, that enabling asset repurposing should be the first steps in a strategy to manage natural gas lifecycle challenges. It is essential that this is underpinned by a fair asset transfer

[1] National Infrastructure Commission, October 2023, The Second National Infrastructure Assessment: Final-NIA-2-Full-Document.pdf (nic.org.uk)

[2] https://www.theccc.org.uk/publication/delivering-a-reliable-decarbonised-power-system/

methodology which unlocks value to consumers across the hydrogen (or CCS) and natural gas networks. This may mean that limited action to accelerate depreciation is necessary within the RIIO-3 period for gas transmission.

The financial proposals do not adequately reflect the level of risk facing gas transmission and therefore underplay the financing challenges.

We welcome recognition of the additional risks faced by the gas sector and careful consideration of how these risks are balanced between investors and consumers and therefore remuneration is needed. At the time of responding to Ofgem's Future System and Network Regulation (FSNR) consultation, we also responded to a related information request which highlighted our early view of NGT investment requirements in RIIO-3, which showed a significant increase in investment when compared to RIIO-2. Whilst a financeability assessment was not carried out at that point, given the actions that were necessary to ensure RIIO-2 was financeable (change of depreciation methodology etc.), it could be inferred that without a change in financing parameters that such a plan would not be financeable at the required investment grade credit rating. We welcome the wider assessment of financeability that the concept of "Investability" introduces given the investment requirements within RIIO-3: this assessment equally applies to NGT.

Whilst we understand the rationale for broadly rolling forward the principles employed in RIIO-2, it is important to consider whether the CAPM framework adequately reflects the forward-looking risks gas networks are facing. We also note that, since RIIO-2 was determined yields on gilts have increased by circa 3.5%. Given this, the approach adopted to setting Total Market Returns at RIIO-2 will not work at RIIO-3. We therefore welcome Ofgem's commitment to considering new evidence when calibrating WACC or wider drivers of financeability. As such, we are working with other networks companies via the ENA to critique Ofgem's application of the CAPM framework and the inputs used to generate an allowed return. We will also be providing evidence, in conjunction with the ENA, that cross-checks of the CAPM output are necessary to adequately reflect the forward-looking risks that networks are facing. We look forward to engaging with Ofgem on the detail.

We do however have concerns around certain proposals Ofgem has included in SSMC, notably how it intends to adjust the treatment of inflation to address the so-called "leverage effect", where we believe elements of the proposals are not consistent with principles set out by the UKRN Guidance. As detailed in our response to Ofgem's Call for Input on inflation submitted in September 2023, NGT is not forecast to benefit from higher-than-expected CPIH inflation due to its higher-than-average proportion of inflation-linked debt. While we have not benefited from the leverage effect, Ofgem's proposals to eliminate the leverage effect by removing the proportion of index-linked debt assumed when calibrating efficient financing costs for the sector is potentially damaging to NGT. It also does not appear consistent with key regulatory principles previously applied when assessing the notional company's financing structure, including network choice of financing structure.

We recognise that the risks the energy sectors are facing are evolving. We therefore agree that Ofgem and network firms should reflect on whether current financial resilience measures are appropriate without unduly restricting financing strategies and impacting financeability. NGT broadly supports the proposals Ofgem has included in SSMC, although the detail on enhanced reporting requirements for the FY24 cycle has yet to be shared by Ofgem. However, whilst NGT already holds two investment grade ratings, given the consequences of breaching the requirement to do so, potentially due to reasons outside of NGT's control, we do not agree with including this as a requirement and support retaining the existing obligation that references networks making "reasonable endeavours" to do so.

Early determination of requirements and milestones is essential.

We welcome the constructive engagement Ofgem is leading to develop the sector specific methodology and associated business plan guidance. We are committed to playing our role in this process. However, it should be noted that, if we are to build a plan that meets any minimum requirements set as a result of this process in an appropriately robust and assured manner, we need early signposting of any such requirements. My team and I look forward to continuing to work on these important points ahead of Ofgem's decision on the sector specific methodology. If you have any immediate questions, please do not hesitate to let me know.

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Dear Akshay,

Thank you for the opportunity to respond to the RIIO-3 Sector Specific Methodology Consultation.

This consultation is an important milestone in ensuring that the RIIO-3 framework is fit for the needs of all energy consumers over the coming years.

The gas transmission network's crucial role in meeting the nation's energy needs during and after the transition to net zero emphasises the need for a prudent approach to a common goal.

In our view, RIIO-3 also presents an incredible opportunity to ensure that the regulatory framework for natural gas and the hydrogen transportation delivery model are in lockstep and the framework must seek to protect consumers from any stranding risk and ensure investor confidence.

The detail of our response expands on these points, and I trust it will support the effective development of the sector methodology. We look forward to further dialogue over the coming months to develop this thinking.

If you have any immediate questions, please do not hesitate to contact our Regulation Director, Tony Nixon (tony.nixon@nationalgas.com), who looks forward to working with you and your team to support the evolution of the framework.

Yours sincerely,

Martin Cook

Chief Commercial Officer, National Gas

NGT Response: Overview Annex

OVQ1. Do you agree with our proposal for how RIIO-3 should interact with the Hydrogen Transport Business Model?

1. **Flexibility is needed across RIIO and HTBM on an enduring basis to enable repurposing and recognise the intrinsic link between activities on both natural gas and hydrogen networks.**

- There needs to be opportunities across the two frameworks to accommodate changes during the price control period to allow repurposing and an efficient process to support approval of the necessary activities and funding.

- Repurposing parts of the existing network for Hydrogen or Carbon Capture Storage (CCS) may, for instance, require reinforcement to the natural gas network. Any costs associated with this will need to be appropriately reflected within the hydrogen or CCS network CBA. Funding associated with such activities will need to be enabled through the appropriate business model and / or appropriately allocated through an asset transfer methodology.

- We note the plan to introduce a re-opener to account for potential developments in gas strategic network planning. This must enable the necessary repurposing activity to be taken forward in an agile and flexible manner. It may be more appropriate to look at improvements to a consolidated net zero mechanism using similar precedent set with the ASTI framework which has been introduced for electricity transmission and doesn't require an initial/final needs case for developmental/pre-construction activities thus enabling a more rapid completion of critical development activities.

2. **Development expenditure (devex) for activities such as early design will be required to unlock repurposing of the natural gas network for Hydrogen and CCS.**

- We anticipate a combination of repurposed and new build assets will form the optimal solution for delivery of the hydrogen network across all geographies.

- One of the key objectives of devex will be to work through the detail of this solution and understand which aspects of the natural gas network can be repurposed. It is not possible to distinguish as clearly as is suggested in the SSMC between new and repurposed activities.

- The momentum on undertaking these activities needs to be maintained and we cannot afford a delay based on uncertainty over which funding route is appropriate.

- Careful consideration needs to be given to the regulatory treatment of such activities – noting that they are not innovation projects and should not be subject to company contribution in the way innovation projects are.

3. A fair asset transfer methodology is a critical tool to enable flexibility across hydrogen and natural gas frameworks.

- Funding associated with repurposing the natural gas network needs to be taken into account as part of a fair asset transfer value methodology. For example, an asset transfer methodology should facilitate the recovery of costs of devex activities that have been funded by natural gas consumers.

- Enabling asset repurposing could be the first steps in a strategy to manage natural gas lifecycle challenges and offers a significant opportunity to mitigate asset stranding risk.

- According to DESNZ timeline, project costs for the first hydrogen business model allocation round are to be submitted Q4 2024, with in depth costs required during 2025 as part of due diligence process. To enable this, an asset transfer methodology will need to be in place in 2024.

- On an enduring basis a process to allocate justifiably shared and specific costs across hydrogen and natural gas consumer base will likely be needed (for example, it may be necessary to recover consequential resilience activity attached to repurposing).

- The approach to asset transfer will be equally applicable for CCS.

OVQ2. Are there any additional activities relating to the development of hydrogen transport infrastructure, or repurposing of natural gas assets, that you think should be funded through RIIO-3, and if so, why do you think this is justified?

4. There are demonstrable benefits to natural gas consumers of repurposing for hydrogen (or CCS).

- Delivery of the hydrogen (or CCS) network will require a carefully considered combination of new and repurposed assets. Given the demonstrable benefits to natural gas consumers, it is appropriate for some costs to be funded by natural gas consumers and enabled through RIIO-3.

- Project Union, our proposed 100% hydrogen backbone, will, where possible, repurpose existing natural gas infrastructure to facilitate the transmission of hydrogen. Our remaining natural gas transmission network will subsequently need to ensure continued natural gas resilience, supplying energy for the foreseeable future.

  To ensure the timely success of the anticipated energy transition, we will require investment in RIIO-3 to deliver hydrogen readiness and enabling activities on the natural gas network. These preparatory costs are essential to prepare our natural gas network for the transition to low carbon energy and will be proposed where we have confidence in the need case and can demonstrate clear benefits to natural gas consumers. The benefits to natural gas consumers of re-purposing include:

- Repurposing **reduces consumer costs** by extending the life of current assets.
- A **whole system approach** utilising transmission scale hydrogen will deliver benefits to consumers by: Reducing renewable generation curtailment from 26% down to 1% by 2050, providing energy system savings up to £38 billion by 2050 and providing the flexibility and security to electricity systems[3].
- **Accelerated wider use of hydrogen:** Access to hydrogen for power generation and energy storage will enable a net zero power grid by 2035, and an overall lower cost and more secure energy system.
- **Mitigation of stranding risks**: asset repurposing will mitigate potential future stranding risks and costs, potentially supporting lower bill profiles in the near term, by mitigating (or even reversing) accelerated depreciation of the gas RAV.
- **Further strengthen incentives to enhance and maintain the natural gas network**: it will be more attractive to invest in maintaining, upgrading and extending the economic asset life of the natural gas network in the near term if there are viable futures to repurpose well maintained assets to transport hydrogen.
- **Operational synergies**: in a transitional period, the natural gas (which are likely to include an increase blend of hydrogen) and hydrogen networks would coexist. This would mean that business support costs required to support the networks (e.g. head office, IT, finance, procurement and legal costs) would be shared over a wider asset and consumer base.
- **Financial benefits**: where a RAV based model is adopted for both, collective management of natural gas and hydrogen investments provides the opportunity to pool financial risks.
- **Reduces decommissioning liabilities** associated with network redundancy: where elements of the existing natural gas network can be re-purposed, this will extend the economic life of the relevant asset, avoiding the need for decommissioning costs in both the near term and long term.
- **Alleviate the risk of cost increases to a smaller user base:** Cost increases driven by a combination of declining user base and accelerated depreciation could be alleviated with natural gas users benefiting from cost reduction and transfers from repurposing the existing network.

[3] Guidehouse (2023), GETIO: Gas and Electricity Transmission Infrastructure Outlook 2050 (nationalgas.com)

5. **Hydrogen readiness activities which bring forward essential intervention on the natural gas transmission network to prevent an increase in security of supply risk prior to repurposing will be needed.**

- In geographical regions which have a high likelihood of repurposing natural gas transmission assets to form part of the hydrogen backbone, essential intervention on the natural gas network may need to be brought forward **to minimise or control the increase in natural gas security of supply risk** prior to repurposing. This will ensure whichever parts of the network we retain for natural gas transportation, are of a good condition and reliable prior to the conversion of adjacent assets to the hydrogen network.

- It is also feasible that additional interventions could be undertaken on the natural gas network, at minimum cost, which enable other natural gas assets to be repurposed resulting in a net benefit to consumers. Such activities could be enabled through the RIIO-3 framework. Any costs associated with this will need to be appropriately reflected within the hydrogen or CCS network CBA. Funding associated with such activities will need to be enabled through the appropriate business model and / or appropriately allocated through an asset transfer methodology.

6. **Where pipeline feeder sections are shortlisted for repurposing for hydrogen (or CCS), all pipeline feeders will require integrity inspection.**

- Maintaining the integrity of our pipelines is critical to their safe and reliable operation. Inspections of pipelines as a pressure vessel are mandated in the Pressure System Safety Regulations 2000 (PSSR); we perform an inspection regime to understand the integrity of the pipeline and allow investigation and remediation to be targeted.

- Integrity inspection will be required whether it be to determine pipeline feeders are of a health that will enable effective isolation (valves are functional etc) to facilitate transition or of good asset health to ensure the retained natural gas network is capable of managing a less supportive service (reduced resilience with reduced pipelines).

- To inform the health of these feeder sections and any subsequent intervention requirements, we may need to bring forward a series of In-line Inspections (ILI) into our RIIO-3 business plan (where not already triggered and included within our business-as-usual ILI programme) dependent on their due date.

- In addition to interventions on the network that will be needed to facilitate the transfer of natural gas assets to our 100% hydrogen backbone, investment will also be required to enable transmission level blending which are discussed further in our response to OVQ3.

7. **Where we have planned asset health interventions, we will evaluate opportunities to perform interventions that deliver both natural gas and hydrogen compatibility; therefore "readying" assets for hydrogen transportation in anticipation of future hydrogen transmission.**

- A key factor in the need to enable blending into the transmission system is the recently approved EU legislation change that outlines the need for European Gas Transmission System Operators (TSO) to coordinate blending across their borders. To ensure we can continue to import natural gas from the EU via our interconnectors with the Netherlands and Belgium (and also to Ireland), we must coordinate with the connected TSOs to ensure we can continue to flow natural gas where it is most needed. To enable us to be ready for the impact of receiving blends, we will need to understand the impact of hydrogen blends on our assets and the required interventions we must perform to ready our network.
- Our FutureGrid facility is delivering essential information on asset capabilities and is helping us prioritise the asset investments we will need to perform in order to safely transport blends on our retained network.
- For example, we are currently installing hydrogen compatible dual stream gas analyser solutions as part of a national replacement scheme on our network. All gas analysers must be replaced ahead of receiving blends of hydrogen, allowing for the ongoing monitoring of natural gas and blended hydrogen. In RIIO-3, we will need to revisit all newly installed gas analysers, commissioning the hydrogen stream (plumbing in the regulators, manifold and install of the Argon bottles).

8. **Hydrogen enablement activities may also be required to inform repurposing decisions and support the preparation of the network for hydrogen transportation.**

- Hydrogen enablement activities may also be required, these might include investments or surveys required, market framework development or system capability assessments required by the System Operator or Commercial and Regulatory works to inform repurposing decisions and support the preparation of the network for hydrogen transportation. Intuitively, enablement activities would be best positioned within our RIIO-3 submission to enable optimisation.

9. **Some of these repurposing-related costs can be identified for inclusion in our business plan submission, others will necessarily emerge within period and will need to be subject to an appropriate uncertainty mechanism.**

- Understanding what work is needed to enable repurposing of the natural gas network is an ongoing activity. Through this, in advance of RIIO-3 we are able to identify a number of investments for inclusion in our RIIO-3 plan. However, some activities will emerge within period and need to be supported by a flexible uncertainty mechanism. As stated in our response to OVQ1, flexibility will be needed across the two regulatory frameworks to recognise the intrinsic link between activities on both natural gas and hydrogen (and CCS) networks.

- As appropriate it will also be necessary to consider appropriate treatment of costs within a fair asset transfer methodology to ensure that any costs incurred have appropriate treatment and allocation over the long term.

OVQ3. Do you agree with the proposal that network costs relating to hydrogen blending at both distribution and transmission level should be included in RIIO-3 net zero related UMs? If no, which mechanism do you think is most appropriate for these costs and why?

10. As stated in our response to OVQ3, a key factor in the need to enable blending into the transmission system is the recently approved EU legislation change that outlines the need for European Gas Transmission System Operators (TSO) to coordinate hydrogen blend across their borders. To ensure we can continue to import natural gas from the EU via our interconnectors with the Netherlands and Belgium (and also to Ireland), we must coordinate with the connected TSOs to ensure we can continue to flow natural gas where it is most needed. To enable us to be ready for the impact of receiving blends, we will need to understand the impact of hydrogen blends on our assets and the required interventions we must perform to ready our network.

11. Our work at our FutureGrid innovation project will provide vital evidence on the work needed to ready our transmission system for blending. More information will become available to better inform required interventions to allow for transmission blending.

12. However, at the time of our RIIO-3 plan submission, there will be uncertainty as to the specific network changes that will be needed prior to accepting blends of hydrogen. Therefore, for transmission, we agree that investment needed to facilitate blending should be managed via an uncertainty mechanism.

13. We have provided a more detailed position in our response to OVQ37 – OVQ38 on improvements that we would like to see with the existing suite of Net Zero reopener mechanisms but most importantly, we agree with Ofgem's proposals that the Net Zero mechanisms today are the most adequate mechanisms to manage developments in hydrogen blending.

OVQ4. What are your views on the proposal of using the GD specific Heat Policy re-opener, the RIIO-3 net zero related UMs, or a mixture of both to fund network costs incurred as a result of the government's 2026 decision on hydrogen for heating (where RIIO is deemed to be the most appropriate funding mechanism for these costs)?

14. As with the response to OVQ1 & 2, there is need for flexibility across both the RIIO framework and the Hydrogen Business model that allows in-period or uncertainty changes to be managed effectively.

15. We do not have a heat policy reopener for GT, nor do we think we need one. But there needs to be flexibility within the broader suite of net zero mechanisms to

ensure any action needed because of the policy decision can be actioned in an agile manner. (SEE OUR RESPONSE TO THE **OVQ35 – OVQ38** ON NET ZERO MECHANISMS)

OVQ5. What are your views on our proposal to not enable funding for further evidence relating to repurposing the existing network for hydrogen heating ahead of government's decision on hydrogen heating in 2026?

16. The needs case for Project Union, a 100% hydrogen backbone, is not contingent on the government's decision on hydrogen heating[4]. That said, reaching net zero is now an imperative and we need to assess all possible options. This needs to be done in a responsible way without shutting down any pathways, so we do not support the position not to enable funding ahead of government decision. Instead, the merits of each proposed activity should be considered in its own right, against the backdrop of relevant policy decisions and other appropriate developments.

17. We believe that having the right mechanism or mix of mechanisms is even more fundamental through this transition and therefore we agree with Ofgem's position in 4.19, that where further evidence might be needed to demonstrate the ability to repurpose the existing gas network to support hydrogen heating, costs relating to these activities could be included in RIIO-3 innovation stimuli or net zero mechanisms.

OVQ6. Should RIIO-3 help to manage future gas network decommissioning costs? If so, do you have views on what these costs could be and what mechanisms should be used, including for anticipatory funding?

18. We note that Ofgem does not expect significant decommissioning activity during the RIIO-3 period. We would support that, given the continuing need for a resilient and safe network over the RIIO-3 period and recognising that across all scenarios demand remains sufficiently high during RIIO-3 to preclude any network decommissioning. However, we consider it important to establish principles for the decommissioning of assets that cannot or will not be repurposed to facilitate hydrogen or CCS networks in future.

19. Current obligations to decommission assets on the network are dictated by health & safety or environmental legislation rather than obligations within the Gas Transporter licence or wider regulation, which does not contain such an obligation. There is however precedent for the costs of decommissioning assets no longer required being funded via RIIO allowances, as was the case in RIIO-2.

20. We note that business models and regulatory regimes for future businesses associated with the Net Zero transition (i.e., CCS) currently being established will include a requirement to decommission assets at the end of life, with financing

[4] DESNZ, (2023), Hydrogen transport and storage infrastructure: minded to positions (P.11): [Hydrogen transport and storage infrastructure: minded to positions (publishing.service.gov.uk)]

packages/revenue models built accordingly. To introduce a requirement to decommission assets at the end of the useful life without a mechanism that involves the collection of allowances to facilitate that activity would seem inconsistent with those new licences and the precedent set during RIIO-2.

21. As noted elsewhere in our submission, establishing a methodology that facilitates the transfer of assets and their regulatory value to new businesses (i.e. hydrogen and/or CCS) allows Ofgem and NGT to protect natural gas customers from the costs of decommissioning assets that will be repurposed.

22. However, not all assets will be repurposed in this manner and therefore there will be a proportion of the natural gas network that will need to be decommissioned, the scope of which will be dictated by health and safety or environmental legislation as licence obligations are currently drafted. As expanded upon in our responses to questions FQ21-23, there are uncertainties around the proportion of the network that will ultimately be repurposed and therefore RIIO-3 should focus on establishing a methodology for asset transfers and then decommissioning remaining assets in the future.

23. NGT believes there are two broad mechanisms that could facilitate the collection of allowances to facilitate the decommissioning of the remaining natural gas assets. Firstly, while the user base remains high, there is an argument that decommissioning allowances should be collected via Allowed Revenue and held for future use. Whilst ahead of the likely need to complete the decommissioning, such a methodology would limit the consumer bill impact vs waiting until the decommissioning activity is due to take place. Secondly, the methodology established to transfer assets between RAVs may offer an opportunity to recover a "premium" for natural gas assets transferred to a hydrogen or CCS business unit that could be utilised to pay for decommissioning costs. Ultimately the valuation of assets to facilitate asset transfers needs to be established and as summarised in our combined response to FQ21, FQ22 and FQ23, there are multiple options, but decommissioning liabilities should be a key consideration in that ongoing discussion.

24. As also summarised in our responses to FQ21-23, it may be necessary to focus on establishing methodologies to facilitate a response to such matters within the RIIO framework but ultimately hold back on a definitive decision until a suitable re-opener/mid-point review or RIIO-4 once there is more clarity on future business models and the subsequent impact on the natural gas RAV.

Scenario & Planning Pathways

OVQ7. Do you agree with the proposal to use the FES framework for selecting the RIIO-3 scenarios?

25. NGT has been utilising the FES scenarios for a number of years as the basis for the supply/demand data that informs the network planning activity, this is primarily the demand data including annual and daily peak demands. However, in recent times the scenarios have become less reliable in establishing the range and profile of credible gas demand moving forward e.g. the progress against installing heat pumps (see Figure 1), the commissioning of offshore wind (See Figure 2), continuing high peak demand. In the last 2-3 years we have not utilised the annual updates as the NESO process for capturing and responding to stakeholder feedback has deteriorated and the desire to include more scenarios that achieve a Net Zero target has meant that the profile for future electricity consumption has been increasing year on year, whilst not being reflected in actuals (See Figure 3), making the pathway and therefore the scenarios themselves less credible.

26. The FES process and majority of scenarios effectively work backwards in time, starting from an assumption that Net Zero is met in 2050 and working back to today's demand. This means that the more near-term end of the projections (i.e. for RIIO-3) lack credibility and are therefore not a sound basis for prudently planning a network that delivers energy security to millions of homes, secures jobs for millions of people and keeps the lights on for a significant proportion of time. FES is geared towards providing a long-term view on scenarios for achieving net zero and does not provide a highly credible or granular near-term view of energy supply and demand. Notably the supply ranges are typically set to balance the national supply and demand rather than reflecting actual use of supplies such as LNG, where we see an increasing proportion of gas entering the UK market. Therefore, the FES approach underestimates the potential range of supply at these types of entry points and also therefore the range of entry flows the gas transmission system has to be planned against; it is also not currently reflective of the supply assessment methodology recently released by DESNZ.

27. These limitations to the FES framework and the execution of its processes must be addressed in future to ensure it is fit for purpose as a planning basis for critical national infrastructure. However, we recognise that FES is currently the only widely available and regularly updated cross-vector framework. It therefore represents the best available framework to inform RIIO-3 planning; but the above limitations must be recognised and taken into account in its implementation into the RIIO-3 process.

OVQ8. Do you agree with the proposal to use FES Leading the Way as the planning scenario for ET in RIIO-3?

28. We have not studied the impact of Leading the Way (LtW) on electricity demand and therefore the impact that this may have on the investment plans for ET. We understand that LtW is a 'high electrification' scenario and therefore as a planning basis it may be appropriate. However, the source of the electricity supply is integral to electricity network planning and therefore it must factor in what the electricity supply pattern could credibly be.

29. This means that whilst the natural gas transmission network needs to incorporate the likely planning parameters of the electricity network in terms of energy generated and location, the ET network and its planning activity should take account of where the likely supply of electricity could come from and how this diversity should be accommodated. This means that for gas fired generation, which will remain a significant proportion of electricity supply going forwards, ET should be mindful of the planning scenarios contained within Falling Short and the proposals we make on the back of it.

OVQ9. Do you agree with the proposal to use two FES planning pathways for the gas networks, ie Leading the Way and Falling Short as the additional common conservative scenario?

30. We do not believe that two scenarios are required to plan the gas transmission network, this will cause confusion and could adversely impact on evaluation of the investment plans and execution of the work necessary to secure the right level of resilience and performance from the gas network.

31. We do not believe that the current LtW gas demand scenario has a significant impact on our proposed business plan as the majority of the investment required in RIIO-3 is based on energy security, resilience, safety and asset health requirements which are similar across LtW and FS. The elements of the plan that are sensitive to gas demand, such as replacement compression, are also sensitive to supply scenarios which we consider will be more volatile going forward in particular the sensitivity of interconnector vs LNG flows.

32. It is possible to establish the areas of the plan based on the prudence of Falling Short that are sensitive to lower gas demand, that may be represented by LtW, so that milestones can be established to confirm the trajectory of gas demand prior to financial/project sanction milestones.

33. Through our discussion with Ofgem, there has been little clarity on what 'to use' means in relation to the FES planning pathways. We have a very specific process for gas transmission planning which follows the current Transmission Planning Code, which means we do not follow any one FES planning scenario/pathway completely when we have better information and therefore, we currently only utilise certain elements of any of the FES planning scenarios in our analysis. We are concerned that without an agreed approach on how we are expected 'to use' the scenarios, our plan could be deemed to be non-compliant with the business plan guidance and we have set out further concerns in this response to the other

associated questions. To adequately assess our business plans for compliance with Leading the Way, it is important for the information that we are required to use for planning purposes to be clear and this will need to be defined upfront by Ofgem against the standards which apply, including ensuring that networks have a shared technical understanding of what is required and the implications for energy security.

OVQ10. Is Falling Short the most appropriate common conservative planning scenario to be used for the gas networks? Or is a common gas network developed scenario more appropriate?

33. Falling Short is the most applicable of the FES scenarios for gas demand that could be used for the gas networks, based on what we currently see and understand as the pathway for gas demand. It is important to recognise that until gas demand actually transfers to another energy vector then the gas network needs to be maintained to the appropriate level of safety, resilience and performance in order to maintain energy security and to accommodate the likely supply quantities and locations to fulfil that demand.

34. Falling Short contains a view on supply quantities but does not adequately accommodate the full credible ranges of supplies at LNG, interconnectors, or storage under the appropriate range of demand scenarios. Therefore, it is necessary to consider this full range of credible supply scenarios in establishing the right level of investment and the timing of that investment, together with legislative requirements such as for emissions and the need to maintain energy security in all its forms. This approach needs to be undertaken independently across both scenarios regardless of what was described in the scenario in order that the gas transmission system can be designed to meet the requirements of our customers and the volatility of the range of supplies to meet a range of demands. We would require this to be made clear in any guidance Ofgem may provide on how to use the scenarios as it is not clear in the consultation as to what Ofgem means by ‘use the FES Framework’.

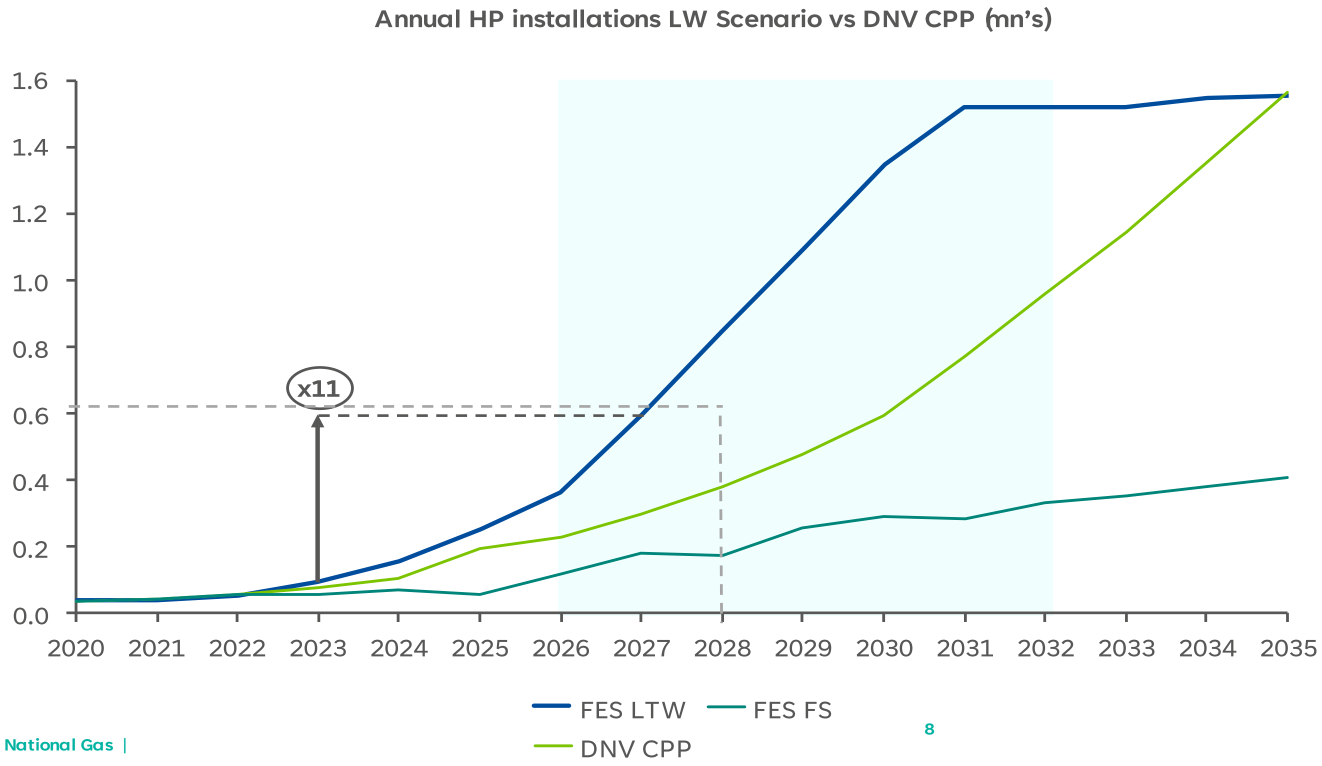
OVQ11. Is it feasible for all network companies to initially plan against FES 2023 before updating business plans in line with FES 2024, as proposed?

35. We currently understand that FES ’24 will be published in June ’24 with a pathway and a counterfactual approach rather than the current four scenarios, this will then subsequently be incorporated into the wider Centralised Strategic Network Plan [CSNP] structure. As such it will not be possible for NGT to carry out the necessary work to incorporate the outcomes of FES ‘24/CSNP into the NGT business plan and associated process ahead of the Business Plan submission in December 2024. Again, as covered in question OVQ9, we would require specific guidance from Ofgem in how they would want us ‘to use’ the output of any updates to our planning.

36. Given that CSNP will be a new process and that the pathways it is expected to generate have not been seen to date it is difficult to say what this process will generate in terms of data, the range of scenarios to meet the net zero target in 2050 or the proposed counterfactual approach.

37. On the basis that the counterfactual is an appropriate scenario, comparable to FS and with the necessary level of data and analysis, then we would look to assess the scenario in line with the timing for proposed longer term strategic planning process for FSO/NESO starting in Autumn of ’24 with us responding in early Summer ’25.

FES LTW assumes more than a tenfold increase in HP installations by 2027 vs 2023 levels



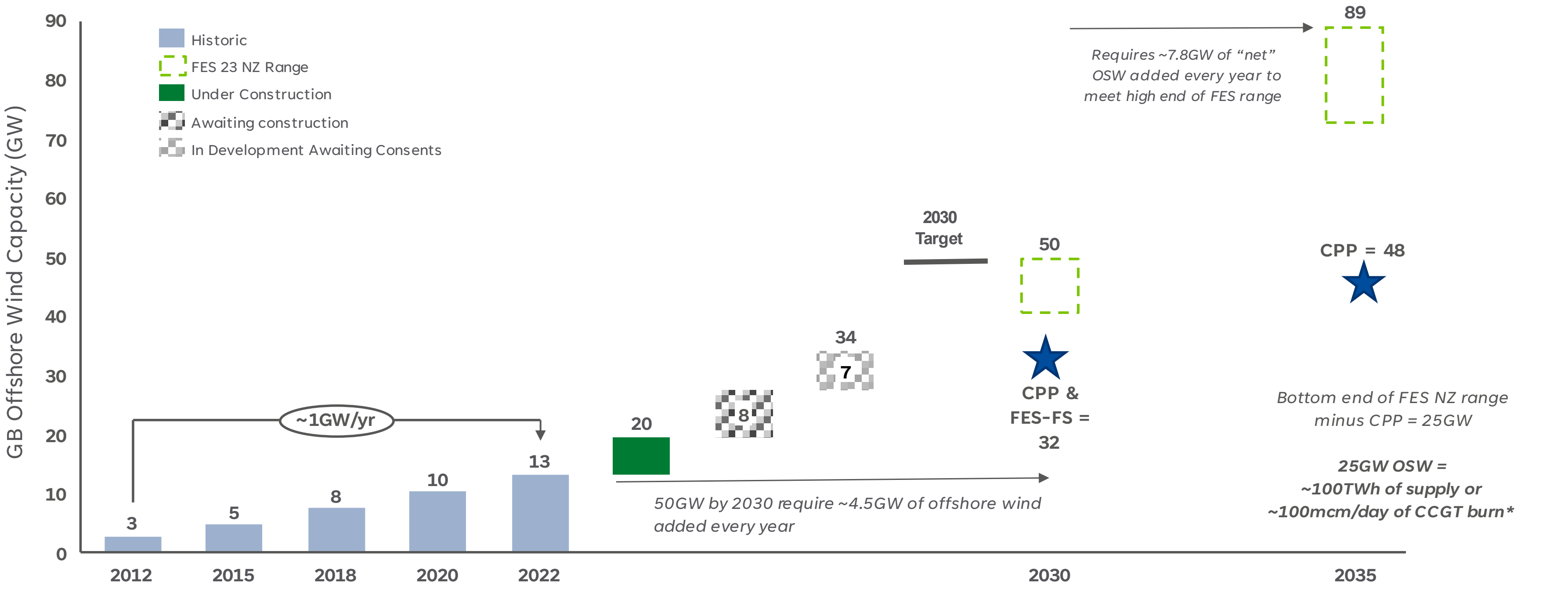
- Heat Pump installations in 2023 reported at ~55,000
- FES LTW scenario has HP installations tripling to 150k in 2024 and over tenfold by 2027.
- Factoring in supply chain constraints and qualified installer availability, DNV see a real acceleration in HP uptake from the end of the decade
- The delta in cumulative HP uptake between FES LTW and DNV's CPP from 2026-2031 = ~3mn HPs (or less gas boilers).
    - *If FES LTW uptake doesn't materialise, the scenario is underestimating residential gas heating demand by ~4bcm in 2032*

National Gas | 8 8

Figure 1

Key Messages / Insights

CPP has a more modest build out of Offshore Wind vs. FES (x3). Offshore Wind growth assumption is a huge factor in overall output for energy mix



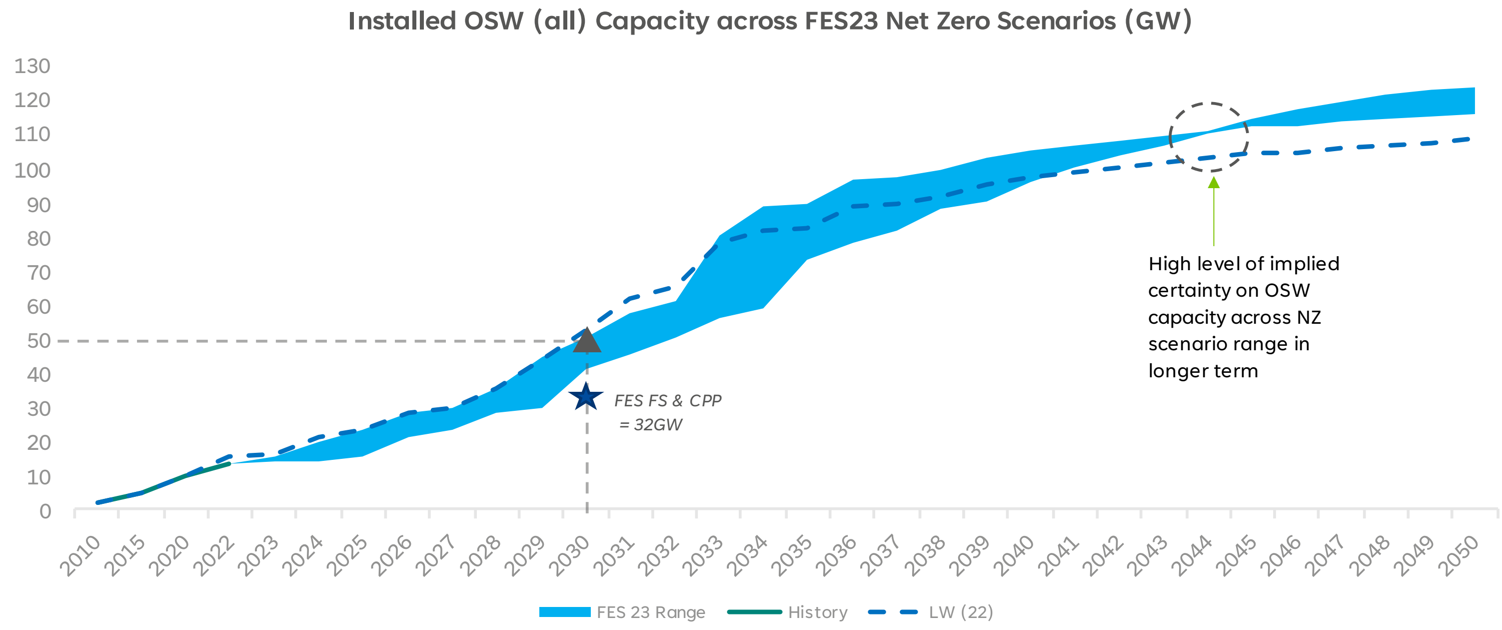
National Gas Transmission | 6

Source: Aurora, LCCC, S&P Platts, * assuming 25GW of capacity is replaced by CCGT

Figure 2

OSW has come a long way, but FES NZ projections are just not credible *(sixfold growth by 2035?)* (2/2)

As OSW makes up >50% of RES capacity in NZ scenarios, even **a small % delta has a large impact on elec generation results**



National Gas Transmission | 10

Figure 3

Output Delivery & Incentives

OVQ12. Do you agree with our proposed approach on the role, scope and format of PCDs?

38. We support that PCDs should only be applied in areas that "directly contribute to the RIIO-3 outcomes or need to be delivered in line with government legislation, standards or guidance." We understand this implies a relatively high threshold for PCDs and should lead to a reduction in their number (and the associated regulatory burden and problematic incentives) for RIIO-3.

39. We support the adoption of a PCD materiality threshold in the order £15m. This too should lead to better and more proportionate targeting of PCDs (and associated regulatory resource burden) to where they are most in the consumer interest.

40. The level of granularity should be in keeping with the outcome focus, materiality, delivery duration and principles of proportionality. For example, as a rule of thumb we would not expect a given £15m PCD to have more than two or three discrete outputs; if PCD delivery spans multiple years we would expect the minimum number of outputs to be one per regulatory period and the maximum number of outputs to be one per regulatory year.

41. In line with considerations of good regulatory practice, "rules" for assessment of PCDs, as defined in Associated Documents, should be set up front and not amended part way through the regulatory period.

42. We recommend for visibility and transparency, Ofgem should maintain on its website a list of all Associated Documents, with links to related consultations and subject to clear version control.

43. We recommend the Cyber Appendices (and related templates) to the PCD Reporting Requirements and Reopener Requirements Associated Documents should be prepared as non-confidential documents which ought to be published and hosted together with the main body of Associated Documents.

44. There should be binding timescales upon Ofgem to perform its role with respect to PCD assessment such that If Ofgem does not discharge its PCD assessment role by the time of the next Annual Iteration Process, then the PCD status reported by the licensee will be deemed to be accepted and the relevant adjustments implemented in the next version of the Price Control Financial Model

OVQ13. Do you agree with our proposed framework for setting financial incentives? Are there any additional considerations that we should take into account?

45. We agree that the framework for financial incentives that was applied in RIIO-2 has delivered value to consumers and remains appropriate for use, updated as

necessary in RIIO-3. One key factor that must be taken into account is the level of control that network companies have over the output being considered. It is not appropriate for incentives to be placed on outputs that cannot be strongly influenced by the actions of the network companies, even when those outputs are of high value and importance to stakeholders.

46. We are of the view that basing targets on historic performance will only be appropriate if it can be demonstrated that the future operating environment will be similar to the historical one, given the increasingly volatile and unpredictable nature of the markets within which we operate.

47. We welcome the suggestion that it may be appropriate to develop incentives that encourage network companies to co-ordinate more effectively, in particular, we believe that this would be relevant to support the energy transformation that will be required to deliver net zero.

48. We do not have strong views in principle on Ofgem's proposals to calibrate ODI-F incentives values as a percentage of RoRE. However, using RoRe as a comparator across sectors may not be appropriate and should not be used as reason to refuse or recalibrate additional financial incentives where these would deliver value to consumers.

49. We agree with the recognition in 6.67 that decisions on incentive strength need to be taken in the round with the overall financial package.

50. We note that the incentive schemes agreed for the RIIO-2 period were agreed in advance of significant changes to the energy landscape in the last few years, in particular the extreme volatility in gas prices, increased uncertainty over the source of gas supplies and consequently many suppliers exiting the market. Incentive schemes that will apply to RIIO-3 need to take account of this increasingly volatile environment to ensure that the balance of risk and reward faced by network companies remains appropriate, including the retention of symmetric upside/downside potential.

51. As previously discussed with Ofgem, we believe the following are desirable features of ODI-Fs:
    a. Priority area for customers and stakeholders
    b. Solution or impact not clear
    c. Simple to understand, operate and report on
    d. Fair return relative to cost and benefit
    e. Performance is within network's control
    f. Drives the right behaviour
    g. Clear, robust and measurable targets
    h. Appropriate contribution to company financeability.

52. In our opinion asymmetrical, or downside only, incentives do not drive the right behaviour or provide an opportunity to outperform in a beyond business-as-usual incentive framework.

53. The RIIO regime under the ex-ante incentive framework with caps and collars has provided a clear structure for investment to drive process and performance improvements. The current ex-ante approach to designing incentives in Transmission has worked well in improving quality of services and encouraging output delivery and improvements which benefit consumers. Where possible, allowances should continue to be set on an ex-ante basis.

54. We note that there has been support for this view from stakeholders in Ofgem's engagement and also recognise that these views have been reflected in updated positions in some specific cases in the published consultation. This principle should be more generally taken into account across the full range of incentive proposals.

OVQ14. Do you agree with our approach to setting reputational incentives? Are there any additional considerations that we should take into account?

55. We recognise that reputational incentives have a role to play in providing reassurance to Ofgem and stakeholders that outputs that stakeholders value are maintained in the absence of financial incentives.

56. Reporting requirements should not be unduly onerous.

57. We agree with Ofgem's overall approach, supported by individual assessments on a case-by-case basis.

OVQ15. Do you agree with our proposals for bespoke outputs? Are there any additional considerations that we should take into account?

58. We have assumed in respect of this question that the definition of 'bespoke incentives' does not apply to NGT as a 'sector of one', and that all our incentives should be classified as common.

59. We would welcome the opportunity to explore other areas of benefit such as Whole System Planning and Facilitating Alternative gases into the NTS and widening the methane venting reduction incentive to include Pipeline venting reduction (see GHG response). We provide a summary of the first two proposals in the points that follow.

60. Whole system Planning ODI-F

- The changing regulatory conditions will require a detailed level of support and a more collaborative and whole systems approach to decarbonising the energy sector as we transition to a low carbon economy. This could be incentivised by establishing a new incentive on all appropriate network companies to collaborate effectively in the strategic planning and delivery of net zero. We note this is in line with Ofgem's suggestion that 'there is more scope for incentives that encourage network companies to co-ordinate with each other more effectively to provide better outcomes for consumers.

- We could see how, with the proposed removal of the Stakeholder satisfaction incentive, a Whole System incentive as a behavioural incentive could be introduced to facilitate the transition to net zero, with the introduction of the NESO. This incentive would target a particular set of stakeholders with specific outputs on collaborating to enable the transition to the low carbon energy economy, instead of our wider set of business-as-usual activities as the gas system and transmission operator licences holder. Additionally, these measures proposed focus on incentivising delivery of outputs beyond business as usual. The incentive mechanism is based on regulatory precedent observed in RIIO-ET2 price control with the introduction of "SO:TO Optimisation ODI-F"[5] which Ofgem had assessed to have delivered significant consumer benefit following a review of the results of the SO:TO incentive trial[6].

- A Whole System Planning approach will ensure that we build a fairer and more affordable energy system, with the best mix of energy generation to provide economic, reliable and resilient green energy for our customers without harming the environment.

- This incentive is aimed at enhancing greater co-ordination between NGT and its key stakeholders. The incentive can be split into a regular and effective data sharing to enable better investment and operational planning element and providing enhanced services (through collaborating on most problematic issues) to NESO thus improving quality of decision-making bringing benefits to consumers.

- This will be accomplished through: Regular data sharing, more robust and coordinated strategic planning, increased stakeholder engagement and feedback.

- More work would need to be done on the precise design of this incentive. It will be important to be consistent with the general incentive design principles outlined in our response to earlier questions. We are keen to engage with Ofgem on these incentive design questions.

61. Facilitating Alternative Gases ODI-F

- We see ourselves as having a role to assist with the transition to net-zero, and we've had feedback from possible customers that this is something they would be interested in.

- Alternative gases can be fed into the existing gas infrastructure and can help to decarbonise the natural gas system.

- Low-carbon connections can have multiple wide-ranging benefits and supports the Government's energy security agenda by diversifying the sources of gas. There is a recent Ireland Commission for Regulation of Utilities (CRU) regulatory

[5] Ofgem (February 2021), RIIO-2 Final Determination Electricity Transmission, SO:TO Optimisation ODI-F: RIIO-2 Final Determinations Electricity Transmission System Annex (REVISED) (ofgem.gov.uk)
[6] Ofgem (February 2021), RIIO-2 System Operator: Transmission Owner Optimisation output delivery incentive: RIIO-2 System Operator: Transmission Owner Optimisation output delivery incentive (ofgem.gov.uk)

precedent in Ireland[7] placing an incentive on Biomethane connections to measure: timeliness, Biomethane output, compliance and market arrangements with a financial reward of +/-£0.25m per annum and also precedent was set by NGET's incentive aiming to accelerate low-carbon connections, by delivering them with shorter lead times (where customers want) and where it reduced carbon emissions[8].

- Through industry engagement we propose to design an incentive to proactively take actions to increase low-carbon connections onto the NTS to reduce GHG emissions and the reliance on natural gas enabling a quicker. This would encourage a more cost-effective transition to a low carbon economy, in line with the governmental policy on meeting climate neutrality and energy security of supply.

- Again, design issues around this incentive need to be worked through and we are keen to engage with Ofgem. One area we will need to consider is the interaction with the Green Gas Support Scheme[9].

OVQ16. Do you agree with our proposal to retain the EAPs and AERs in RIIO-3? Please provide reasonings for your position.

62. We agree with Ofgem's proposal to retain the EAPs and AERs in RIIO-3. The EAP provides a framework for NGT to monitor progress and helps to drive behavioural changes, the AER provides the mechanism for reporting on our progress which meets stakeholder and customer requirements. Our customers want to see that we are delivering against our targets and minimising our environmental impact.

OVQ17. What are your views on the new proposed AER format with Commentary and KPIs?

63. The proposal for the new AER format with commentary and KPI table is welcomed. This approach would provide a consolidated data table rather than the current reporting format which consists of a KPI table and various other figures detailed throughout the report. This approach should be more efficient and would enable comparability across the networks.

OVQ18. Do you agree with our minded-to position of retaining the reputational incentive on TOs and GDNs for reducing their BCF?

64. We agree with Ofgem's minded-to-position of retaining the reputational incentive for reducing BCF for GDNs and TOs and would be happy if this was extended to

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[7] Commission for Regulation of Utilities, (July 2023), CRU Consultation on the PC5 Regulatory Framework: CRU202370_CRU_Consultation_on_the_PC5_Regulatory_Framework.pdf (divio-media.com)
[8] Ofgem (February 2021), RIIO-2 Final Determination NGET Annex, Quality of Connections Survey ODI-F: https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determination_nget_annex_revised.pdf
[9] GOV.UK, October 2023, Green Gas Support Scheme (GGSS): Green Gas Support Scheme (GGSS): open to applications - GOV.UK (www.gov.uk)

NGT. This aligns to our business commitments and Net Zero ambition. A commitment within the RIIO-2 Environmental Action Plan was to develop a science-based target by 2023. The Science Based Target initiative (SBTi) organisation is currently developing the sector-specific oil and gas methodology, however NGT have developed our decarbonisation strategy aligned to the corporate SBTi methodology which provides a glidepath commitment to Net Zero by 2050 with an ambition of 2040.

OVQ19. Are there any other suggestions you would like to make regarding reporting standards?

65. It would be beneficial if there was clarity on the categories that were to be included in the BCF – as mandatory and where reporting has matured and developed an identified mechanism to include further categories. Additionally, we request that the emissions factor application be specified for the RIIO-3 period. For example, currently the conversion factor of 25 is applied for methane, will this this be amended to 28 as per the GHG Protocol to ensure consistency? Should the same conversion factors be used throughout the reporting period to normalise the figures across RIIO-3?

OVQ20. Do you agree with our minded-to position to withdraw the Environmental Scorecard and incentivise improvements in environmental impacts through the Annual Environmental Report (AER)? Please explain your reasoning.

66. We agree with Ofgem's minded-to-position to withdraw the Environmental Scorecard and incentivise improvements in environmental impacts through the AER.

67. The Environmental Action Plan (EAP)/AER are a duplication of the Environmental Scorecard elements and thus the proposal would help drive reporting efficiencies.

68. The original measures within the Environmental Scorecard were linked to elements of the National Grid Environmental Action Plans, which post business separation, will need to be decoupled and aligned to gas specific measures.

69. With this realignment we would welcome a recalibration of measures. Currently performance and outperformance measures are less significant to our overall environmental performance, and so more emphasis should be placed on higher value environmental activities.

OVQ21. Do you consider that there are other areas which require financial incentives which cannot be captured by the AER? Please explain your reasoning.

70. In Dec 2022 we submitted the final submission of the Net Zero Pre-construction and Small Net Zero Projects Re-opener (NZASP) uncertainty mechanism to address methane emissions from operating the NTS.

71. Our proposals covered three themes.

    1. Investment in expanded mobile recompression capability to capture vented emissions occurring during pipeline maintenance, diversion, and pigging operations.
    2. Trials of solutions to reduce vented emissions from the compressor machinery train.
    3. Expanded fugitive leak detection and repair at above ground installations.

72. Themes 1 and 2 are addressed in the Greenhouse Gas Compressor Emissions incentive and our proposal to incentivise Pipeline Emission reductions (GTQ5 and GTQ6 respectively).

73. Theme 3, Expanded fugitive leak detection and repair at above ground installations is likely to have a baseline performance established in Y1 of RIIO-3, once established with more knowledge of fugitive emission sources and associated repair costs, we are proposing an incentive mechanism can be switched on to recover our spend on monitoring and repair. This incentive would be based on emissions saved as a result of the programme.

74. We are keen to discuss our options and preferred route with Ofgem on which funding mechanism/incentivisation to allow/encourage fugitive leak detection and leak repair over beyond our baseline repair funding.

OVQ22. Do you have any views on our proposals for the NARM framework?

75. We support the proposed framework and commit to working closely with OFGEM and other sectors to ensure the details of the NARMs Incentive mechanism are appropriate.

OVQ23. Do you have any views on our proposed long-term approach to embedding climate resilience, including the principles for embedding climate resilience?

76. The gas network will perform a critical role in maintaining the secure energy needs of our nation across the transition and beyond. It is positive to see recognition that flexibility is needed within the price control to manage uncertainty around the future of gas networks and provide funding to ensure continued secure and resilient supplies.

77. Ofgem's proposed long-term approach to embedding climate resilience into the regulatory process is proportionate and reasonable.

78. We support Ofgem embedding consideration of and investment in climate resilience into the price control mechanisms.

79. Remaining focused on mitigating the worst impacts of climate change through emission reduction and achieving net zero goals is critical but changes in our climate is already embedded following greenhouse gas concentration rises we have already seen in the last century.

80. We are starting to see the consequences of climate change in the UK, with more frequent weather extremes, Storm Arwen which Ofgem reference and the summer of 2022. Ensuring energy networks individually and the energy system as a whole adequately assesses the risks posed by climate change and takes appropriate cost-effective adaptation measures where resilience is compromised will be important as the frequency of these extremes of weather is forecast to increase.

OVQ24. Are there any early learnings we should be aware of/incorporate to make progress on this in RIIO-3 or beyond?

81. Ofgem should consider the mandatory sustainability reporting which corporate entities must undertake now and, in the future, when embedding climate resilience into the energy network regulatory price control mechanisms.[10]

82. For example, the Task Force on Climate-Related Financial Disclosures (TCFD) reporting requirements in end of year company accounts requires consideration of physical and transition climate risks and aims to ensure companies make suitable financial provisions for adaptation and resilience to climate change. Although aimed at investors this drives network companies to consider climate adaptation and resilience measures and investments when it comes to ongoing business sustainability. TCFD requirements are incorporated into the International Sustainability Standards Board (IFRS) S1 and S2 standards which are likely to be mandatory sustainability reporting standards required by the Financial Conduct Authority in 2025. Ofgem should be wary of duplication.

83. As stated in the National Grid Gas third round climate change adaptation report the gas transmission system is inherently resilient to climate change although we have started to see some isolated incidents resulting in adaptation measures being needed. Consideration of interdependency of the gas transmission system and of energy networks and systems to other infrastructure owners (transport, telecommunications etc) should also be a focus for climate resilience frameworks. This is likely to pose more of a resilience threat to the gas transmission network.[11]

[10] UK Sustainability Disclosure Standards [UK Sustainability Disclosure Standards - GOV.UK (www.gov.uk)]

[11] National Grid Gas PLC, (October 2021), Third Round Climate Change Adaptation Report [A4 simple report 1-col no divider Nov 2019 (nationalgas.com)]

OVQ25. Do you agree with our suggested approach for embedding climate resilience into RIIO3, namely: introducing resilience strategies; developing forward-looking resilience metrics; and introducing climate resilience working groups?

84. Yes, but be cognisant of already existing climate change related reporting requirements such as TCFD today and IFRS S1 and S2 in future. Climate resilience metrics at transmission level are very different to when at distribution. At DNO level resilience can be more easily seen in household disconnections etc, this doesn't work for gas transmission.

85. There are also challenges around investment in climate resilience given projections on future gas supply and demand and the need for a gas transmission/distribution network. Climate resilience investments are long term when based on climate projections and potential future resilience risks, otherwise resilience investment is reactive.

86. There has been a lot of thought and debate about climate resilience metrics in the Energy Network Association climate resilience working group between electricity DNOs and ET. Both the GDNs and ourselves have been observers on this group for the last 12-18 months. A climate resilience metric will need to be developed for gas as a group created to develop it outside of the ENA of which gas networks will no longer members as of 1st January 2025[12].

OVQ26. Do you agree with the proposals that we have set out around the resilience metric?

87. We do but as stated earlier a resilience metric suitable for a gas transmission network is very different from distribution and needs some thinking about. We would question why existing metrics on availability and reliability of the gas transmission network are not suitable as failure or decreased reliability of the gas transmission network as a result of the impact of climate change would manifest itself in these existing metrics.

OVQ27. Do you agree with our proposals on workforce resilience?

88. NGT agrees with the proposals that a robust plan around workforce resilience is required.

89. There are significant challenges within our industry and within NGT to meet increased demand activity in a range of disciplines. Headcount will increase substantially in a number of areas and across a range of skills (some of which are new and as yet undefined – definition will be required from external bodies, it will

[12] ENA, (November 2023), ENA Membership: [ENA membership – Energy Networks Association (ENA)]

be critical that we work with those bodies to define the skills and qualification requirements).

90. There are skills areas which are seeing increases in demand (notably IT, Cyber, Data). These areas will require significant input at a national level, across industries, as the skills are not Gas or even Energy Industry specific. There will be competition from across sectors. Fundamental to addressing this for the entire UK will be the adequate supply of entrants to each of the relevant skills sectors. This will require funding and input at Government level to ensure that skills training and higher education has adequate capacity.

Truth Telling & Efficiency Incentives

OVQ28. Do you agree with our proposed key objectives for truth telling and efficiency incentives?

91. We broadly agree with the proposed set of objectives for a Truth Telling Incentive and Efficiency Incentive. These need to be overlayed with the additional overarching objective, that they should be well **targeted, simple, and transparent.** We would like to see these objectives adequately reflected in the design of the mechanisms.

92. For example, a more targeted approach to assessing costs within sectors, that recognises sector differences, will ensure there is a level playing field across all sectors when assessing ambitious cost forecasts rather than the one-size fits all approach of the current BPI mechanism today.

93. Ultimately of course, the primary objective of the Business Plan Incentive is to incentivise the companies to submit better information in their business plans than would otherwise be the case. This is the sole purpose of the BPI and Ofgem should take care not to let other objectives cloud a laser-sharp focus on this. The BPI as designed in RIIO-2 led to arbitrary outcomes which actually penalised companies such as NGT who submitted strong information – this outcome is already damaging to the incentive and must be carefully avoided in RIIO-3. We note that even describing it as a "truth-telling" incentive is pejorative – it implies that Ofgem's prior expectation is that companies may not "tell the truth" in business plans. The reality is that we face genuine uncertainty and cost forecasting is inherently challenging and risky – the BPI should instead be described as an "information revelation incentive" which is there to help Ofgem understand how companies have built forecasts and assessed future uncertainty to inform their cost projections, to enable full scrutiny and engagement from Ofgem.

OVQ29. What are your thoughts on our proposals relating to minimum requirements under an evolved BPI approach?

94. We agree with Ofgem on the importance of maintaining an incentive for the minimum level of information [i.e Stage 1 BPI] required in our business plan, but a fundamental shift is needed from the RIIO-2 approach which was sometimes very difficult to understand in terms of what level of information was needed and in our best endeavours to ensure we provided Ofgem with high quality information, NGT received a penalty in RIIO-2 based on those minimum requirements, which in our view was arbitrary and the regulatory judgement was incorrect.

95. Therefore, we agree that any minimum requirements must be **clear, targeted and specific** to be truly effective, but this also needs take into consideration the need for it to be **fairly and proportionately applied.**

96. We also note the proposal to retain the current BPI approach in assessing both "completeness" and "quality" of our plans and welcome Ofgem's acceptance that assessment of quality comes with a degree of subjectivity and therefore **we are not opposed to assessment of quality playing a lesser role when deciding on any symmetrical incentive.**

97. We take the view that assessment of quality is important, but it needs to be flexible, and it is also crucial that both **networks and Ofgem have a shared understanding of the expectations.**

98. **Transparency** is also equally important to the extent possible on **how exactly "quality" will be assessed going forward** – we believe that Ofgem needs to provide some guidance on this.

99. In our view, when considering any symmetrical incentive, any penalty linked to minimum information should only be based on completeness rather than quality. Quality should only be taken into account when determining upside. It is also important for any assessment of minimum requirements **to take account of sector differences.** This may seem insignificant but is crucial to maintaining a level playing field across all sectors, as a one size fits all approach to such an assessment also directly contributed to NGT receiving a penalty in RIIO-2.

100. Finally, given these proposed changes will be **new and largely untested, greater proportionality of BPI requirements is needed** in the final RIIO-3 framework.

101. As we have said previously, the primary objective of the Business Plan Incentive is to incentivise the companies to submit better information in their business plans than would otherwise be the case. Therefore, any changes to the design must recognise that companies need sufficient time to act and to facilitate these changes and therefore, the proposals Ofgem presents needs both drastic

simplification and clarity, so that we have a shared understanding of what Ofgem expects us to be working towards.

OVQ30. What are your thoughts on an 'in the round' assessment of cost forecasts as opposed to a high/lower confidence breakdown and assessment?

102. In principle **we agree with assessments of costs in the round over line-by-line assessments of costs**, but a framework or **methodology for assessing costs will be needed based on standards that we have agreed with Ofgem.**

103. For NGT, It is vital that the BPI is underpinned by a robust and transparent cost assessment process, which recognises the specificities of each sector. A robust suite of cost assessment tools are already available today and must be appropriately applied to each sector.

104. Cost assessment must be robust; and as Ofgem acknowledges **in [7.25] that there is limited scope for comparative benchmarking** in the transmission sector compared to distribution in assessing cost confidence and in a sense, benchmarking is not possible for us and without a robust cost assessment method, the BPI will just give arbitrary outcomes and fail to achieve objectives.

105. Assuming a robust cost assessment is in place, we would welcome an approach that is "in the round" as opposed to breaking cost base into higher/lower confidence. In particular, the rule Ofgem seemed to apply at RIIO-2 was that costs can only be higher confidence if they can be benchmarked. This meant a large proportion of NGT's cost base was deemed low-confidence basically 'by definition' - leading to a highly arbitrary outcome. We would therefore welcome the removal of CDIR at RIIO-3 or, alternatively, if Ofgem wishes to retain its confidence-based assessment, it must do so in recognition that NGT is in a sector of one to avoid the inherent absence of a level playing field as there currently is across sectors.

106. In view of this, **we do not consider that introducing a financial penalty for cost forecasts that are high relative to Ofgem's own benchmark addresses the need for a clear cost assessment framework** that recognises sector specificities.

107. We equally believe that there will be sufficient opportunity for challenge and review of our proposals during the Ofgem review of business plans before draft determination.

108. Fundamentally, Ofgem is still seeking to ensure there is cost confidence in our plan, albeit using a simpler approach. A better approach for NGT as a sector of one could be establishing robust **"investment proposal principles"** to create a comparator and could give greater certainty around level of costs to Ofgem and Stakeholders and this should provide the basis for establishing cost confidence in our plan.

109. At the Cross-Sector Working Group organised by Ofgem in November 2023 on Efficiency and truth telling incentives, we emphasise the need for Future cost assessment approach to recognise the unique challenges in benchmarking NGT being in a sector of one, to ensure greater proportionality in the application of BPI requirements.

110. NGT is inherently unique. We are the only National Gas Transmission System in the UK. We do not have a natural comparator to assess our costs against to demonstrate we are operating efficiently in delivering our key objectives of providing our consumers with safe and reliable access to the gas when they need it. In addition our activities are not highly repeatable in the same way the activities of other sectors are (e.g. GDNs).

111. Each of the four Gas Distribution Networks (GDNs) are able to compare their costs and measure their efficiency against each other using regression analysis together with established like for like benchmarks that provide the regulator with a transparent and an accurate reflection of what their costs are. This provides a strong level of confidence that their costs are robust and comparable – improving information asymmetry.

112. NGT is unable to utilise comparative regression analysis, but instead relies on utilising historical cost actuals, competitive procurement events and estimations based on historical tendered projects.

113. To be appropriately benchmarked against Ofgem's own assessment, it requires transparency of the detail behind the benchmark used and the ability for NGT to challenge Ofgem's findings, decisions whether resulting from benchmarking or SME Review.

114. We are therefore proposing to establish robust "investment proposal principles" to create a comparator to which the GDNs have at their disposal. This provides Ofgem with transparency on how we've derived our costs and it also delivers a **robust methodology to calculate costs that can provide Ofgem with confidence that we have a process that enables a transparent approach** and review of how they have been derived our costs. For example, each investment will also comply with an **internal Scope, Volume and Cost (SVC)** standard which provides a level of confidence that is open to scrutiny and maintains a consistent approach to deriving costs. Please see response to GTQ36 for more detail.

115. We believe that the adopted approach following the removal the complicated CDIR should be replacing it with a **simple and clear cost assessment process** that is aligned with a clear set of "minimum requirements" and recognises sector specificities, as this will minimise the need to apply undue discretion when judging compliance.

OVQ31. What are your thoughts on an 'in the round' assessment of business plan ambition as opposed to requiring and assessing CVPs?

116. We support Ofgem's preferred option to remove the CVP element of the BPI mechanism in favour of more effective mechanisms that drive consumer value.

117. There could be some benefits to assessing **business plan ambitions in the round in parallel to cost assessments in the round**. However, we most avoid introducing complexity to the assessment process **to ensure that the approach Ofgem is proposing is compatible with its objectives** – in particular meeting Ofgem's test of simplifying the framework as originally intended.

118. In principle, we agree with assessments of costs in the round but we reiterate the importance of **cost assessment framework based on standards that we have agreed with Ofgem**. We do not believe that the CVP will drive any additional value for consumers.

119. **We also take the view that ambition needs to take on a wider meaning**, For example, Ambition could be how as networks we have been proactively mobilising for the price control by being proactive in securing supply chains, taking risks ahead of setting price control to ensure we can deliver at pace and taking more proactive steps ahead of the price control to ensure we can provide robust plans that will ensure that the Gas Transmission Network can continue to provide that critical resilience through the transition or even getting our network ready to support the transition to Hydrogen and Carbon Capture Utilisation and Storage .

120. Finally, The Ofwat approach provides some template to assessing "ambition", although we caution that there is no evidence yet that it is the silver bullet. However, in the round may be more suited to an iterative process with networks and without clear and transparent requirements, this is also an area that requires subjective assessment and therefore it lends itself to the need for flexibility in approach. **Given the degree of subjectivity, it doesn't seem appropriate that any form downside should be considered when deciding on how to incentivise networks.**

OVQ32. What are your thoughts on the size and strength of any truth telling incentive?

121. We do not have strong views on the size and strength of the incentives.

122. In RIIO-T2 FD (published in December 2020) Ofgem proposed penalties on NGT under BPI, resulting in a total penalty of £21.7m and with the best endeavours, we want to work with Ofgem to dispel any concerns of perceived information asymmetry.

123. We note that Ofwat's approach in Pr24 could have potentially been less punitive given the penalty range is lower (+/- 30bps of RoRE) compared to BPI used by Ofgem during RIIO-2 (+/- 2% of Totex) but on the flipside has the potential to limit the upside that networks can achieve.

124. This may offer an alternative when considering the size of the incentives, but we do not hold any strong views.

125. However, our view is that reward needs to demonstrate consumer value and penalty needs to demonstrate harm to consumer and it is not clear, nor was there any evidence that there was consumer harm to the extent of penalty we received.

OVQ33. What are your thoughts on any alternative approaches that could be used instead of an evolved BPI?

126. Ofwat's PR24 approach is underpinned by some valuable principles which on its own **does not provide a complete alternative but could complement the existing RIIO-2 BPI** approach which is also underpinned by some important principles.

127. Ofgem could **adopt some of the principles that Ofwat has used** in PR24 determinations to simplify the existing BPI framework. For example, these could involve a) **two-step process for determining both TIM and BPI penalties** and reward.

128. The **proposed removal of both CVP & CDIR makes BPI then more closely aligned** with regard to becoming a two-step process.

129. Ofwat's approach also uses a short-list of six core areas covering 22 criteria to assess meeting of minimum requirements, making it less complicated than the current Business plan guidance and we would like to see a very tight package of "minimum requirements" set for RIIO-3

130. The "ambition assessment" approach under the Ofwat model gives latitude to Ofwat to make subjective assessments but to a large extent it makes sense because Water companies by their nature are comparable businesses and the changes they have made really works in their sector, very similar to gas distribution. For the transmission companies with less comparators, we need to make sure the right methodology is in place to ensure there is a level playing field.

131. NGT received a penalty in RIIO-2 and with the best endeavours, we want to work with Ofgem to dispel any concerns of perceived information asymmetry and so our preference is for Ofgem's requirement to be **clearer and more explicitly define where it is directly linked to the incentives and setting of efficiency rates.**

OVQ34. What are your thoughts on the options for calculating the sharing factors and do you see strong reasons for changing the overall strength of the sharing factors relative to RIIO-2?

132. Of the options presented, NGT supports some of the principles applied in Ofwat PR24 approach, in that the sharing factor should reflect ambitious cost forecasts as long as the methodology for assessing the cost confidence is agreed upfront.

133. A framework or methodology for assessing costs will be needed based on standards that we have agreed with Ofgem and is crucial regardless of which ever approach Ofgem settles for to ensure there is a level playing field in how cost confidence is assessed across characteristically different sectors.

134. NGT is of this view as the sharing factor provides the appropriate balance of protection to consumers and network firms. Furthermore, it provides an incentive to network firms to enhance cost estimation methodologies between price control periods, which should in turn reduce information asymmetry and provide more comfort for regulators, consumers and network firms alike. For this reason NGT **does not support holding sharing factor at the rate established in the Final Determination of RIIO-2**.

Managing Uncertainty

OVQ35. Do you agree with our proposal to retain the Net Zero Re-opener with its current scope and parameters for RIIO-3?

135. We agree with the proposal to retain the Net Zero reopener, but we believe there is an opportunity to streamline and consolidate across net zero mechanisms that is flexible across different Net Zero needs.

136. We also note Ofgem's acknowledgement that the Net Zero Re-opener has not yet been used in RIIO-2 and despite it being a relatively broadly framed re-opener to enable Ofgem respond to technological, markets and network role developments in RIIO-2, its links to fundamental shifts in Government policy, significantly limits its ability to facilitate the pace of change needed in RIIO-3.

137. A consolidated mechanism will help to make reopener applications more agile, and more outcomes driven by reducing gaps between funding for project stages and allowing the different stages of Net Zero projects to scale depending on the materiality.

138. This idea is not to introduce complexity to the existing process of pre-engagement and establishing triggers but to **close the gap where continuity** is needed between projects stages which under the current RIIO-2 framework, will see some projects become ineligible for further funding beyond the early design stages.

139. RIIO-3 will be a critical time for progressing the infrastructure needed to deliver not only net zero, but also the interim carbon budgets especially for projects that have exhausted the NZASP funding mechanism route and the Net Zero reopener mechanism in its current form, clearly has some limitations.

140. To deliver Net Zero by 2050 (see Figure 5), the mechanism needs to be able to support the development of related projects at pace and the next Price Control period affords us an opportunity to consolidate the **Net Zero Reopener** and the **Net**

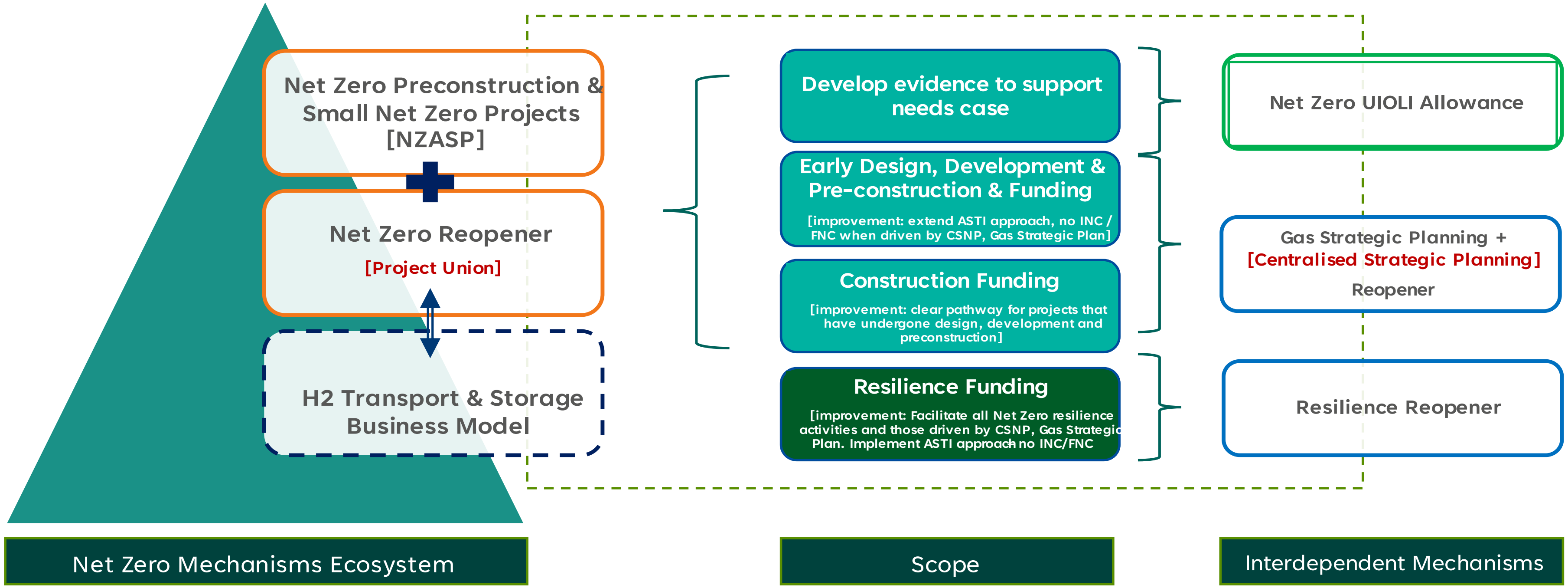
Zero Pre-construction Work and Small Net Zero Projects Re-opener into an effective consolidated Net Zero Mechanism that will allow us to the unlock solutions needed to tackle these strategic challenges at different stages (see Figure 4).

141. It is also important to consider this suite of net zero mechanisms alongside the other package of uncertainty mechanisms, specifically the newly proposed resilience and gas strategic planning reopeners. The proposed resilience activities are to be driven, amongst other things, by government and FSO requirements - this could interact with net zero drivers. Equally, the gas strategic planning reopener is to address investment needs driven by the FSO's outputs - which could also be net zero and resilience related.

142. As per our feedback to OVQ41 and GTQ1, we do not think an overlap of the mechanisms is a problem in its own right. Provided that the mechanisms are flexible and agile enough to enable timely investment to be taken forward in response to the appropriate and identified drivers.

A possible ecosystem for Net Zero mechanisms in RIIO-3

A consolidated mechanism will provide an end to end strategic mechanism to manage net zero investments on the network, considered to be beneficial to natural gas network users from early development to delivery.



National Gas Transmission |

Figure 4

A strong case for a consolidated Net Zero Uncertainty Mechanism

The Drivers for Net Zero on the Gas Network

- Net Zero Strategy - [250 – 460TWh of H2 by 2050, DESNZ]
- **Hydrogen Transport & Storage** & **Carbon Capture [CCUS]** Business Models
- UK Energy Security 2022 [10GW H2 production by 2030]
- Role of H2 in Decarbonisation of power [CCC]
- Legislation i.e. Industrial Emissions Directive [IED]
- NIC Report: Second National Infrastructure Assessment

What do we need to deliver Net Zero & consumer outcomes?

- **Robust Mechanism**: Agile & Flexible NZ mechanisms that allows us react to within period changes & developments and enables continuity in pace of project delivery across phases of development
- **OPEX:** To enable us to continue to develop the **evidence** and **strong economic case** for Network Net Zero solutions
- **DEVEX:** To support **technical feasibility** and **design development** to meet **government targets**
- **CAPEX: No regrets + Anticipatory investment requests from NESO strategic plan,** for the benefits of wider society
- **Resilience:** Methane network must continue to reduce emissions & provide insurance policy through the transition

What are the benefits to the consumer and outcomes?

- Whole system benefits of transmission scale H2 and CCUS
- Mitigation of stranding risks, Avoids Decom. Costs
- More attractive to maintain methane network near term [with repurposing opportunities]
- Opportunities for asset transfer of the methane RAV to H2 & CCUS
- Opportunity for operational and financial synergies

What are the implications / risks of not acting?

- Hydrogen economy is delayed
- Delays the decarbonisation of power i.e. Reserve Offtaker role
- Compressed time frame = inefficient choices
- On the back foot in securing & leading the global supply chain
- Higher lifecycle costs for both natural gas and hydrogen / CCS users

National Gas Transmission |

Figure 5

OVQ36. What are your views on our proposal, in principle, to retain the Net Zero and Re-opener Development Fund UIOLI for RIIO-3? What are your views on the types of projects it could fund and how it would interact with other sector specific price control mechanisms?

143. We agree with Ofgem's "proposal in principle" to retain the Net Zero and Re-opener Development Fund UIOLI for RIIO-3

144. We believe it will still be appropriate for developing evidence needed for hydrogen and CCS activities where the benefit to natural gas consumers can be demonstrated, as well as for specific natural gas only activities. The mechanism is effective across a number of activities.

145. The interaction between RIIO framework and HTBM needs to be carefully considered and worked through in greater detail than is outlined in the SSMC to ensure that design gaps do not arise between the two frameworks. The UIOLI may continue to play an important role in funding hydrogen (and CCS) related projects where a funding route is not provided under the HTBM (or CCS BM).

146. Similar to ET where projects funded through this mechanism has allowed for pre-construction work to be undertaken, the same applies to GT where projects funded through this mechanism have allowed projects for Pre-FEED work to be undertaken.

OVQ37. Do you think we should retain the NZASP for GD and GT? What should its scope be and what kind of projects would you expect to be funded through this re-opener in RIIO-3?

147. We believe that the current scope of the NZASP reopener remains adequate in unlocking funding for net zero related early design and development work and should be retained. As with our response to Q35, we believe there is an **opportunity to consolidate this with the Net Zero reopener**. We also believe there is opportunity to make it simpler and more effective to access funding in the early stages of design & development with greater scrutiny at the later funding stages.

148. The NZASP reopener has been crucial in unlocking Pre-FEED funding for Project Union as well as methane emissions reduction and monitoring projects and will continue to play a key role in future CCS activities and wider net zero investments driven by, amongst other things, future outputs of the NESO's centralised strategic network plans.

149. It is important to recognise that the costs associated with this reopener should not be automatically considered as pass through (as indicated in table 4 of the GT Annex), given the guidance for NZASP makes clear that licensees will be engaged on the potential regulatory treatment of any approved funding. As indicated in

Table 6 of the Overview Document, it is a reopener and appropriate regulatory treatment should be considered flexibly within the reopener process.

150. We also think it is also important to have a **consistent and aligned approach [as used in the ASTI model in electricity]** between Gas and Electricity in terms of mandatory contributions requirements. There is currently a prohibitive requirement for Gas networks to make contributions as a default position, even when some of these net zero activities cannot be deemed to be significantly innovative. Such an approach may delay or even prevent critical net zero investments from being taken forward.

151. We expect a number of crucial projects can be funded under the NZASP reopener in RIIO-3.

152. **Project Union:** This project will deliver a hydrogen transmission backbone by repurposing existing transmission pipelines and connecting industrial clusters and strategic hydrogen production sites with storage and users across the UK, by the early 2030s and aligns to current UK Governments strategic objectives. Development expenditure has been taken forward through NZASP within RIIO-2 and it would seem appropriate for future funding of this nature to be considered in RIIO-3.

153. **Methane Emissions Reduction**: We have also used the NZASP to unlock funding which will allow us to reduce Methane Emissions by up to 15% when operating the NTS especially during compressor venting and the NZASP mechanism will continue to play a key role in unlocking funding for related activities that may emerge.

154. **Carbon Capture & Storage**: Following the publication of DESNZs CCS business model update which provides a clear pathway for how the revenue support model could be utilised in the future, the framework will need to support the development of evidence and early design phases where there are repurposing opportunities that could benefit natural gas users in the long run.

155. **NESO Strategic Planning**: The National Energy System Operator will be responsible for multi-vector planning and like today where its strategic plans are driving increased investments on the electricity networks, there will need to be a mechanism in place to facilitate anticipatory and low regret investments. As stated in response to Q35 and Figure 4, there is interaction here with the newly proposed gas strategic planning reopener.

156. **Hydrogen Blending**: In the overview document, Ofgem also proposed that this mechanism could be used to unlock funding for Hydrogen Blending on the transmission network and to a lesser extent, the consequential impacts of Hydrogen for heating. As per our response to OVQ3, we support this proposal.

157. Biomethane Injection: We will need to place greater focus on maximising the amount of Biomethane gas coming onto the network, which will require us to identify and remove any barriers to entry to allow owners and operators to deliver as much green gas as can be produced. This will also help to unlock more opportunities within the Market to increase Biomethane production and support Governments ambition of 30 – 40 TWh of biomethane production by 2050, which Government has said would help the UK achieve net zero cost effectively[13].

158. **Interaction with HTBM**: We need to ensure that we continue to unlock funding through the early phases of the project and both Ofgem and DESNZ have a crucial role to play in how the RIIO-3 framework interacts with the HTBM.
The regulatory treatment component will also need to enable alignment across natural gas, Hydrogen and CCS RABs in the future, to allow repurposing activities and asset transfer between RABs.

OVQ38. Do you have any views on consolidating the net zero related re-openers and the UIOLI allowance?

159. We have said previously that there are some benefits to merging the "**Net Zero Reopener**" and "**Net Zero Pre-construction Work and Small Net Zero Projects [NZASP]"** mechanisms to deal with all Net Zero development stages.

160. A consolidated mechanism that is **proportionate and simpler in the early stages of design, development & pre-construction** and provides continuity in funding by accommodating the different materiality thresholds, to bridge the gap between the funding stage gates is possible.

161. It will be important that requirements can scale with materiality and project stage so that a consolidated mechanisms can unlock funding in a proportionate way without increasing the requirements for early stage and low materiality funding.

162. Fundamentally, we believe that the "Net Zero and Re-opener Development Fund UIOLI" plays a different role to Net Zero Reopener" and "Net Zero Pre-construction Work and Small Net Zero Projects [NZASP]" in terms of the ability to support small Net Zero facilitation and low regret projects in a timely manner, which is crucial and so we take the view that it needs to remain a standalone mechanism from the other net zero reopeners. (See Figure 6)

163. In RIIO-2, it has enabled key net zero projects to develop the evidence that is needed ahead of reopener submissions and will continue to play a role in ensuring that we do not delay important development work in key areas like hydrogen and CCS which can demonstrably benefit natural gas consumers.

[13] DESNZ, (February 2024), Future Policy Framework for Biomethane Production: [Future policy framework for biomethane production: call for evidence (publishing.service.gov.uk)]

Our blueprint for consolidating net zero mechanisms

It is essential to continue to enable ongoing net zero activity which has uncertainty over scope and need at start of period and therefore we are proposing **3 key mechanisms**

Consolidated Net Zero Uncertainty Mechanism

[NZASP + Net Zero Reopener] ←→ [Resilience and Gas Strategic Planning reopeners to support H2, CCUS & NESO Strategic Planning Outputs

Consolidate "**Net Zero Reopener**" + "**Net Zero Pre-construction Work and Small Net Zero Projects [NZASP]**" into Ofgem's proposed to deal with all Hydrogen Development Stages

The mechanism should also have the ability to adapt to interactions between **RIIO-3 framework and the Hydrogen Transportation and Storage Business Model** and **CCUS Developments.**

We will need a mechanism that is proportionate and **simpler in the early stages of design, development & preconstruction** and provides continuity in funding to bridge the gap between the funding stage gates.

A **dynamic mechanism that will facilitate alignment across Methane & Hydrogen RAB**, to enable repurposing and asset transfer between RABs.

Wider triggers need to be recognised beyond FSO's CSNP triggers alone, to provide **pathway for project union, biomethane dev, blending & consequential resilience** investments

Resilience Reopener

Gas Strategic Planning Reopener

Future Innovation Mechanisms

*[**Retain NIA and Improve SIF** to make it a more effective mechanism to drive innovation]*

NIA : Continue to feature as a key mechanism over the course of the entire RIIO -3 i.e. Ofgem's approach to setting NIA over 3 years in ED2 increases risk for areas like PHDs which takes 4 years – currently even with NIA over 5 years price control, if not started in 1st year, cannot be undertaken

SIF: Greater autonomy for networks over **SIF discovery stage funding** or;

The NIA could be "**enhanced**" to allow you do more discovery to allow more high quality innovation that warrants competition

Net Zero Development UIOLI

*[**Retain UIOLI & broaden scope** to include NZ related activities]*

To continue to support small Net Zero facilitation and **low regret projects** which is crucial and so we take the view that it needs to remain a standalone mechanism from the other net zero reopeners

In RIIO -2, it has enabled key net zero projects to develop the evidence that is needed ahead of reopener submissions and will continue to play a role in ensuring that we do not delay important development work

National Gas Transmission |

Figure 6

38b. We are seeking views on our proposal to evolve the non-operational IT capex reopener, replacing it with a mechanism comparable with the RIIO-ED2 Digitalisation Re-opener.

164. The RIIO-2 ED2 approach that was agreed in the final determination, we believe was a materiality threshold of 0.5% to trigger. In our view, for an investment, this seems reasonable if as we understand it, is based on our totex baseline position for the IT submission – we would welcome some clarity on this, given the volumes of potential investments needed.

165. We would welcome a re-opener window as we did in RIIO-2, however our preference is to have the window towards the middle of year 2 of RIIO-3 to allow enough time to consider investment candidates for the latter period of RIIO-3 (we took a similar approach for RIIO-GT2 which seemed to work quite well for us and Ofgem).

OVQ39. Do you agree with our proposed position to retain the Coordinated Adjustment Mechanism for RIIO-3? If it were to be retained, what design and incentive considerations could we implement to enhance the utilisation and value of this mechanism?

166. We recognise that Special Condition 3.8 the Coordinated Adjustment Mechanisms has not been triggered in RIIO-2.

167. However, coupled with our proposal for an ODI on whole system planning (see OVQ15), our view is that there may be a role for it in RIIO-3. It is credible that one of the outcomes of whole system coordination could be a reallocation of activities where it is in the interests of consumers to do so.

168. The mechanism currently has annual window which may be too rigid to support effective utilisation. A more flexible and agile approach may enhance the use and value of this reopener at RIIO-3.

OVQ40. Do you agree with our proposal to allow physical security costs to be submitted through a broader resilience re-opener?

169. In principle we agree with the proposal to allow physical security costs to be submitted through a broader resilience re-opener, though we would expect flexibility for the change in CNI ratings. In addition, the approval process would need to be simplified as it currently requires approvals from DESNZ, NPSA and Ofgem which creates delays.

OVQ41. Do you agree with our proposed approach to introduce a resilience re-opener?

170. In principle we agree with the proposed approach to introduce a resilience re-opener. This vehicle could be used to handle changes in investment requirements arising from amendments to the transmission planning standards or other resilience initiatives such as identification of single points of failure.

171. We agree it is appropriate to have a reopener that can deal with the changing energy landscape. Recent global events and the consequential impact on the GB gas market have illustrated the need for flexible regulation to ensure the energy system remains resilient and able to meet GB energy needs.

172. As we move towards global decarbonisation, it is possible that we will see new energy supply and demand trends develop which could alter the expected flow patterns across energy networks; reinforcing the value of such a reopener.

173. As stated in our response to OVQ35 and GT1, it is important to consider this suite of uncertainty mechanisms. We recognise there are some drivers which could be considered to cut across multiple reopener mechanisms. We do not think overlap of mechanisms is a problem in its own right, provided that the mechanisms are flexible and agile enough to enable timely investment to be taken forward in response to the appropriate and identified drivers.

OVQ42. Do you have any views on whether the opex escalator should be retained and if so, how we could evolve the opex escalator for RIIO-3?

174. The Opex escalator has worked as expected in the RIIO-2 price control and it has therefore addressed its key objective of ensuring networks are funded for varying operating costs in line with increased activities when UMs are granted.

175. Furthermore, it is reasonable to expect networks to plan resources for the level of baseline activity granted and therefore that additional allowances should be granted should additional activities be necessary.

176. Therefore, we support proposals to retain the Opex escalator mechanism in RIIO-3 and we are happy to work with Ofgem to ensure that in RIIO-3 (which is dependent on the mix of baseline and UM allowances) it is calibrated to the correct scope (i.e. it provides for a fair estimate of the incremental costs incurred once a UM is granted) but is balanced against the need for efficiency/practicality.

177. The mechanism currently employed in RIIO-2, which grants additional allowances for relevant UMs based on the proportion of CAI in the overall business plan, appears to reach that balance in that it utilises a pre-approved spend ratio without requiring CAI costs to be submitted with each UM.

178. To that end, as we work through to RIIO-3 we need to ensure Ofgem and networks are aligned on which Re-openers are in scope for the Opex escalator and that this alignment is clearly reflected in the licence.

OVQ43. Do you have any views on how we should effectively monitor the delivery of UMs?

179. We support the current RIIO-GT2 monitoring approach including the Pipeline Log (table 8.10 of the annual Cost and Outputs RRP submission), which provides Ofgem with an annual forecast of planned re-opener submission and associated values.

180. We would welcome (aligned to the NGT Pipeline Log) an Ofgem work programme and Ofgem owners to enhance visibility on timescales of anticipated Ofgem directions following re-opener submissions. The number of re-openers in RIIO-GT2 compared to RIIO-GT1 did increase significantly and the decision times have had an impact on the deliverability of projects.

181. As part of the RIIO-3 Licence we would also support a review of the Re-opener Guidance and associated templates (such as Engineering Justification Papers). Regarding guidance for re-openers, we would welcome more detail on Ofgem's assessment principles.

182. Alongside re-opener timelines of Ofgem determinations, PCD assessment dates should be clearly defined in relevant guidance and agreed at the point of Ofgem's final determination on PCDs set following re-opener decisions.

Cost of Service

OVQ44. Do you have any views on whether to evolve the RIIO-2 methodologies for RPEs and ongoing efficiency for RIIO-3, and if so how?

183. Inflation protection of allowances is a central pillar of how RIIO regulation has operated and should remain so to retain investor confidence in the regulated sector in the UK. RPEs form a crucial building block in providing this and in principle should add a layer of precision that general CPIH indexation would not.

184. The RIIO-2 period was characterised by significant and often inconsistent levels of inflation depending on the activity and specific cost pressures that were felt by NGT in a number of key areas. As presented to Ofgem in its most recent RRP cost visit (November 2023), case studies of major projects or categories of spend illustrated the inflationary pressures on key inputs to our activity. These case studies included demonstrating that on our Hatton project encountered cost increases in civils work (steel) of c.32% vs the original budget set with reference to RIIO-2 business plans (the same increases for enabling works, plant and materials being 62% and underground piping diversions 27%). In respect of physical site security projects cost increases ranged from 23% on low voltage cable ducting to 85% in for wire fence panels.

185. We therefore support the retention of the RPEs methodology but believe evidence on whether specific indices referenced in it provide the required level of

precision should be re-assessed, particularly where RIIO-3 activity will require increased resources in areas characterised by scarce workforce or subcontractor resource. As such, in conjunction with certain members of the ENA, NGT has appointed KPMG to perform a detailed assessment of the cost exposures relevant to gas network firms in the RIIO-2 and RIIO-3 periods and what approach appropriately provide protection against them, notably the choice of indices and respective weighting in the RPE mechanism. This will include analysis of the forecasting of index performance. While actual index performance is included in the mechanism and we would not propose changing that, for the purposes of enhancing forecasting accuracy KPMG will also assess alternative approaches. While this work is ongoing we would be happy to share more detail on the approach and early findings with Ofgem ahead of the main report being published.

186. In respect of ongoing efficiencies (OE), we believe that the existing methodology has struck the correct balance between fairness and incentivising networks to innovate and embed new ways of working, as long as allowances are fairly granted at the outset. However, we consider it appropriate to assess the basis of expected ongoing efficiency gains, notably the link to expected UK productivity gains. Evidence suggests that RIIO-2 levels of ongoing efficiency gains may no longer be appropriate given the recent trends of UK productivity. Accordingly, NGT, in conjunction with certain members of the ENA, has appointed to Economic Insight (EI) to assess the appropriate academic evidence on whether UK productivity gains justify retaining RIIO-2 ongoing efficiency assumptions.

187. The broad approach to setting OE has stayed the same (i.e. benchmarking against productivity datasets such as EU KLEMS) but in recent years there has been an apparent disconnect with levels of productivity in the UK and the level of OE. EI's report, which will be published in due course and accompanied by peer reviewed academic research, will focus on:

- An analysis of UK productivity growth, which illustrates that UK productivity has largely stagnated in recent years across multiple industries, implying that it is an economy-wide phenomenon. For example, UK Gross Output TFP stood at 100.4 in 2008 and only 100.8 in 2019.
- Comparing this trend to how OE has been set by regulators in recent periods, which has tended to trend upwards. For example, Ofgem set OE at 0.7% for capex and 1% for opex at RIIO-1 compared with 1.15% for capex and 1.25% for opex in RIIO-2.

190. These trends suggest that the method for setting OE for RIIO-3 should be carefully considered for RIIO-3, hence commissioning this piece of work. EI will consider the following:

- Whether productivity should be measured on a gross output or value add basis, taking into account recent CMA judgements on the matter and ongoing PR24 process to assess the appropriate weighting between the two
- As a result of how they are measured, productivity metrics take into account catch-up efficiencies and/or economies of scale, based as they are on capturing a change in output for a change in input. This can lead to OE

being overstated and will require comparators used to compare gas networks to be carefully selected.

- An assessment of how productivity metrics take into account the impact of technological change, notably the extent to which embodied change is included and whether an adjustment to productivity measures is appropriate in setting OE
- Given their role as an element of inflation, efficiency gains will be reflected in inflationary mechanisms used in RIIO (I.e. CPIH indexation). As such, OE challenges should be set to be equivalent to the difference between industry-specific OE and that already captured in CPIH
- Considering how calibration of outcome incentives and OE interact, with a view to avoid duplication given efficiencies gains can be measured across cost savings or output increases.

191. EI will also focus on the practical choices that will be faced in setting OE for RIIO-3, such as:

- Time periods used in determining OE and the need for a transparent framework that aligns to internally consistent time horizons and full business cycles.
- The selection of suitable comparators based on clear criteria that should reduce the need for making adjustments, notably to assess the impact of the regulatory framework.
- Aligning on a methodology that provides a stable and consistent approach that operates equally effectively in times of high and low productivity.

OVQ45. Do you have any views on the potential application of RPEs and ongoing efficiency to re-opener applications?

192. By their nature, re-opener applications and the approval process take place in a significantly closer timeframe to delivery than baseline projects. Proposals therefore capture current thinking on how a project will be delivered, contains up to date costing from either internal resources or subcontractors and leave limited time to innovate delivery approaches before work starts and therefore generate efficiencies.

193. The UK does however face significant challenges in respect of the availability of labour and subcontractors to deliver infrastructure projects. Networks are therefore exposed to potentially significant and at times unforeseen cost pressures that may support the extension of RPEs to re-openers, particularly those delivered over a number of years.

194. For example, a number of projects in gas transmission are multiyear projects and may span more than one price control. Most are tendered and typically contractors would index rather than factor it into their bids and therefore it seems reasonable to allow RPEs to be recovered for this type of re-opener application. By the same principle, ongoing efficiencies should also be applied but only in

combination with RPEs; both or neither mechanisms should be applied to multi-year projects given the aligned principles of each.

Cyber Security

OVQ46. Do you agree with our proposed approach to cyber resilience in RIIO-3?

195. We support the stated aims: namely to simplify and streamline the price control, to improve consistency and reduce reporting burden (for both licensees and Ofgem), to consolidate RIIO cyber resilience guidance documents, and to provide flexibility to respond to changes in threat or requirement for new/additional cyber resilience intervention.

196. With respect to consolidating RIIO cyber resilience guidance documents, we are aware that at the commencement of the RIIO-2 period the Cyber Appendices to the PCD Reporting Requirements and Reopener Requirements Associated Documents were (rightly in our view) prepared as published documents. Since the documents contained guidance generic to all network companies this content was itself non-confidential in nature. This practice aided transparency, visibility and compliance. However, part way through the RIIO-2 period the Ofgem custom and practice changed such that subsequent attempts to consult upon and amend the cyber guidance have been classified as “Official / Sensitive” and therefore not published. In our view this change in practice has been detrimental to principles of good consultation and detrimental to regulatory transparency, visibility and compliance. We recommend Ofgem should maintain on its website a list of all Associated Documents, with links to related consultations and subject to clear version control. We recommend the Cyber Appendices (and related templates) to the PCD Reporting Requirements and Reopener Requirements Associated Documents should be prepared as non-confidential documents which ought to be published and hosted together with the main body of Associated Documents.

197. There ought to be careful considerations to the effective date for any changes to guidance & related templates. It should be recalled that the preparation of reopener applications represents many months of activity and can entail large data sets. It would be disruptive, inefficient and contrary to good regulatory practice if for example changes in templates were requested at one month’s notice.

198. There is also a need to recognise that there is also substantial overlap in the materials / content expected from the Competent Authority NIS annual report and the PCD narratives. These 2 should be combined into a single product.

Innovation

OVQ47. Do you have any views on our proposal to retain a flexible allowance, providing evidence for why you think that it should, or should not be, retained?

199. We agree with Ofgem's proposal to retain a flexible innovation allowance. The benefit to this type of funding mechanism is in allowing agility to identify new opportunities and innovations and progress them quickly whilst embedding innovation into the energy networks and enabling a team to build an understanding of the business needs, global technology landscape and disseminate key learning.

200. Below, we have responded in detail to Ofgem's particular concerns around:
   a. Accountability
   b. Duplication
   c. Demonstration of outputs
   d. Prioritisation of NIA over SIF by some licensees

201. We agree with the commentary provided on maintaining the flexible innovation allowance to provide baseline funding for idea and concept development, consortium identification and creation and project collaboration and dissemination, alongside the delivery of research and development projects prior to them moving into demonstration and implementation. We have found that the NIA fund has enabled us to form new relationships with third parties our core business processes would struggle to achieve (start ups etc) providing them key information on how to provide solutions to the energy system and ensuring we have the optimum solution to deploy on the network.

- **Accountability**
  Through RIIO-2 we have focussed our NIA and SIF funding activities on energy transition and consumer vulnerability projects, as per the funding criteria, this has led to network resilience and improvement projects needing a novel arrangement. The Operational Innovation team has been formed to manage projects that can no longer be funded through Ofgem innovation incentives to find routes through investment programmes, business funding and alternative external funding. This has led to a slow in the progress of more risky non energy transition projects but has provided a good process and method for progressing higher TRL innovation across the business. A key focus for the team is in building the innovation culture across the business and has been assisted by the "PA consulting" culture review in 2023.

  The value tracking activities undertaken by NGT are consistent across NIA and SIF projects. We review projects against several criteria; Maturity, Opportunity, Deployment Cost, Project Cost, Financial Savings, Safety, Environmental, Compliance, Skills & Competencies and Future Proofing. This enables us to through idea selection prioritise the projects that will provide the largest benefit, through delivery track our predictions against actual benefits and on completion report on delivered benefits through case studies.

Our projects go through research, development, demonstration, and implementation. As with SIF we expect CBA activity to be estimated at a high level of detail at a research phase and firmed up with quantitative values as we move through development, demonstration and into implementation. The method taken for value calculation is in defining the baseline costs (what would the cost be if we did nothing) vs the method costs (costs once the innovation is deployed). There may be multiple baselines and methods especially at an early phase of development. We detail each and provide insight into the most probable output.

The current Innovation Measurement Framework allows the networks to showcase high level numbers for benefits but is limited by a single view of financial savings. We have made suggestions to improving this through the inclusion of safety, environmental and other benefits that has been built into the forms for FY2024. We accept that the networks each measure benefits differently, this can make it difficult to provide a common understanding for Ofgem. Equally the value tracking processes for each network are embedded in their innovation structure and process which can be difficult to change.

In reference to 12.22 we welcome an update to the NIA project PEA to reflect the topics raised, these are all available. We also would request a review of some of the questions currently asked as some duplication through the document is seen. An alignment of the SIF and NIA questions would be sensible to enable an easy transition between the funding mechanisms. SIF phase questions should also be consistent with an increased level of detail as you move from discovery to beta.

We welcome updates to the registration approach for NIA and suggest it aligns to SIF to enable an easier transition between the two funding routes.

- **Duplication**
  The energy networks meet monthly across gas and electricity and weekly as the gas networks to review any new NIA or SIF projects alongside other regular topics such as strategy and process. Each project must have a project notification loaded and logged in the project notification area, each network is to then provide insight into duplication or interest in being involved in the project. Where a potential duplication is flagged it is the responsibility of the network owner to follow up with the relevant networks or projects to ensure the project scope does not duplicate past work. The result is to either discontinue the activity or adjust the scope to focus on areas not yet covered. It is important to note that whilst a project may cover a similar technology or topic the application could be dramatically different and therefore not duplicate work done previously. Where past projects fail to deliver a solution to implementation, these may be revisited at a later point once the technology has been further developed outside of the energy networks.

Regarding the overlap between NIA and SIF, we have found that the Discovery and Alpha phase activities could be undertaken through NIA, this has been resolved through the ability for projects to enter the SIF programme directly at Alpha and Beta. At these early phases it can be difficult to know if a full Beta demonstration is required and this is where the flexibility of the NIA process prevents third parties in committing resource to something that will not progress. NGT has been careful not to duplicate work done in NIA projects through the SIF programme and has selected projects that required the SIf approach. We have found that projects required for the energy transition have not been selected for SIF funding, this has led to the projects needing to be progressed through NIA or another method. We have ensured that feedback provided through SIF is utilised to ensure the scope of any further work is relevant and aligned to the innovation criteria. An example is in the metering and gas analysis of hydrogen within the high-pressure networks and how we can reduce the need for replacement of assets through smart live calibration. We have no concerns with additional routes to preventing duplication and improved visibility of our current activities to Ofgem.

- **Demonstration of outputs**
  The NGT team track the value of their projects from idea generation through to implementation. This is manged through the project database and ends with a case study being developed and published on our company website. Over the last 3 years we have made this a focus for our team and developed a sub team to focus on the delivery of project outputs into the business and wider networks. Whilst the NGT projects are focussed on high pressure gas networks several topics span the wider networks such as digital capability etc we support other networks in understanding the outputs of our projects directly whilst also providing all key information on the Smarter Networks Portal.
  We welcome improvements to the Smarter Networks Portal to improve accessibility and traceability. The system has been upgraded in recent years but has some limitations and long lead times on delivering updates.

- **Prioritisation of NIA over SIF by some licensees**
  At NGT we have approached both NIA and SIF in a balanced manner, we are however conscious that at key points in the year workload may lean toward one funding mechanism or another due to the assessment periods for the SIF process. We believe that using a flexible innovation allowance to undertake Discovery and Alpha activities is sensible in providing a more balanced approach throughout the annual period.

  NGT have progressed several SIF projects relevant to the challenges set by Ofgem. In R1 we submitted 11 Discovery applications and have successfully moved 2 projects through to Beta. In R2 we submitted 5 Discovery applications and are working on 2 Alpha projects. In R3 we have submitted 7 Discovery proposals that we are excited about progressing in 2024. Alongside this we have developed a portfolio of 77 NIA projects through at various stages of development from delivery to implementation and are working on a further 45 projects in the pipeline. Whilst the number of projects seems much greater in the NIA space the scale of the projects is much smaller than those in the SIF process.

We do not believe that NGT has favoured one fund over another and believe that large scale demonstration projects will always be fewer in number than the early research and development activities.

Working with the Gas Innovation Governance Group we have developed the following overview of the innovation mechanisms and how they would work together in RIIO-3. This infographic covers some topics from following innovation questions:

Network Innovation Incentive (NII)	**Research & Development**	Baseline Innovation Fund for each network (90% funded) Projects <£1.5m	**NIA**	Budget for the RIIO-3 period to be managed by the network to develop projects, stakeholder collaboration	**TRL 2-6**
	Innovator Accelerator	Innovation Fund for Innovators supported by networks (TBC%)	***new**	Ability for innovator led activities to be funded, supported by networks but not led	**TRL 4-7**
	Demonstration	Innovation Fund for Projects >£1.5m, requiring approval and peer review. (up to 90% Funding). Assessment made by 3rd party to ensure consistent approach and meets energy system needs.	**SIF**	Request for funding window open every 6 months Submission must include evidence of past (NIA) work proving demonstration capability and all key elements as seen today in SIF process. Could be managed through UKRI or other system. Option to start with short Alpha phase or move straight to Beta	**TRL 4-8**
	Future Regulator Sandbox	Funded through NIA/SIF or Reopener activity	***new**	Ability for networks to trial innovative approaches to the energy system in live trials led by Ofgem. Sits alongside the current regulatory sandbox.	**TRL 7-9**
	Scale Up & Hand Over	Baseline Innovation Fund for each network (up to 90% funded) Projects <£1.5m	***new**	Budget for the RIIO-3 period to be managed by the network to disseminate projects, deliver benefits across energy system and implement	**TRL 7-9**
	Implementation	Business Funded deployment activities (0% funding)	**BAU**	Business to self fund implementation past the first deployment and ensue driven into relevant investment programmes	**TRL 9**

Figure 7

OVQ48. Do you have any views on our proposal to retain a competitive network innovation funding pot, that continues to focus on key challenges facing the energy sector, with phases to de-risk the pot?

202. We agree with the proposal to retain a competitive network innovation fund. The SIF project process enables peer review of large-scale project demonstration and delivery. We believe there is a need for this type of fund.

203. We see a benefit in enabling early SIF development work to be undertaken through the network managed innovation funding. It is important that the networks have the ability to direct this fund on topics relevant to their challenges.

204. The ability to attain funding for larger scale demonstration projects is vital to enabling implementation on the networks. Whilst we undertake network to network peer reviews on NIA projects it is important to get a broader view of the projects when they are requesting larger amounts of funding and looking to deploy technologies for the future.

205. We also consider that having a monitoring officer through the project period provides guidance and identifies areas of improvement. This can only benefit the end result of the project and is important in ensuring a project that can be implemented robustly.

206. We do have concerns on the peer review selection for projects as we would like to ensure that we have both technically aligned assessors alongside project management and wider contextual participants. This can be difficult when projects under one theme can span a broad range of topics.

207. Whilst we have been able to develop projects through Discovery, we believe we could accelerate the process through NIA funding and provide more robust outputs than seen in the 2 month Discovery period. We have however found that the Discovery phase has been beneficial in forming a strong collaborative team with our consortium, providing an urgency and joint vision to enable the next phase of funding. We would hope to replicate this in the NIA fund when developing projects to ensure we are in a great position to apply to Alpha/Beta phases.

208. Developing topics that are relevant to our network challenges is important in putting our best proposal forward to SIF. We should also consider how multiple NIA projects across the energy networks can come together as a SIF project proposal, the regulatory sandbox proposed by Ofgem could provide an opportunity for us to demonstrate a whole system set of projects instead of running 5 separate projects.

209. We consider that the issues seen at the beginning of RIIO-2 regarding SIF and NIA duplication are due to networks having already started development of projects assuming that the NIC process would be available in RIIO-2. Now that the SIF process is embedded, and a level of consistency provided there to be less chance of networks duplicating across NIA and SIF.

OVQ49. Do you have any views on how the structure of the price control innovation funding could be adapted to better focus on whole systems problems, and ensure strategic alignment with other public sector initiatives?

210. We believe there is an opportunity for broader challenges that could bring in sectors outside of energy to support each other in developing net zero solutions for the future.

211. Specifically, we have developed strong relationships with the water and nuclear industries through RIIO-2 that have had similar challenges to use in regards to network and asset inspection, repair and the wider challenges of the energy transition. We believe that other industries such as transport, industry, energy production and mining could all benefit from cross sector collaboration.

212. We would welcome cross sector challenges and funding to promote wider collaboration and enable us to more easily work with wider consortium on elements that will benefit the energy network but also the wider UK landscape. We have focussed on this topic in our R3 SIF applications but are conscious that the energy network consumer should only fund elements that directly benefit them.

213. As mentioned, we have developed strong relationships with the water and nuclear industries through RIIO-2 that have had similar challenges to use in regard to network and asset inspection, repair and the wider challenges of the energy transition. We believe that other industries such as transport, industry, energy production and mining could all benefit from cross sector collaboration. This is not commonly promoted through sector specific funding, and we should consider how we can ensure consumers fund energy network relevant work whilst providing a wider benefit. Potentially joint funding calls with other regulators or funding bodies would be an option. For instance, could Ofgem and Ofwat have a joint fund on electrolysis or hydrogen, Ofgem and Ofcom on IOT and digitalisation, Ofgem and IUK on nuclear, battery technology etc.

OVQ50. Do you agree with our proposal to continue with a similar level of innovation funding, and if not, could you provide evidence for why a different amount is required, including consumer research you are aware of into their willingness to pay for network innovation?

214. We agree with the proposal to continue with a similar level of innovation funding. The level of funding requested should be justified by the network over the price control period based on network specific challenges and activities.

215. We believe that a whole period fund as deployed in RIIO-2 is beneficial over an annual fund which we moved away from after RIIO-1. The % of revenue innovation funding provided in RIIO-1 was then limited over an annual period and led to projects being rushed through for the end of a financial year. The RIIO-2 funding has required the networks to think about their likely portfolio and plan ahead whilst also providing flexibility to bring in new technology entries to the market and deprioritising lower benefit projects.

216. We have found that in RIIO-1 we spent roughly £5m a year, with inflation through RIIO-2 we are spending closer to £7m a year and have further ambitions to increase innovation in RIIO-3 so would be looking for around £8m a year. The additional requirement is due to the ramp up of activity through the RIIO-3 period surrounding the hydrogen backbone and repurposing of the UK NTS assets. We will be justifying our proposed increase in the business plan with a view of the likely projects and activities needed through the RIIO-3 period.

217. The SIF funding pot should be reviewed after Beta projects for R3 are selected. With the early additional of the EDNs and the fast-approaching deadlines for Net Zero, it may be appropriate to increase the overall budget. Whilst we understand the proposed Beta cap of £10m per project it is possible larger scale necessary activities will large business cases will be proposed and should not be solely dismissed based on value.

218. We agree with the proposal to ensuring the funding is maximised and spent efficiently. Through RIIO-2 we have further developed our processes to ensure a competitivity in the project bidding process and enabling evidence of the selection process. Whilst we believe this should be common across all projects, we do also propose a level of flexibility for new market entrants and areas where single source is the only reasonable approach. As enabled today through the innovation funding.

219. NGT has not conducted extensive research into consumer willingness to fund the energy transition but through our Project Union activity we are engaging all direct customers on the approach and supporting activity. We will consider this question as we progress through to business case submission.

OVQ51. Do you agree there is a need to expand the scope of innovation funding to be more inclusive of third parties?

220. NGTs Innovation portfolio works with a broad range of third parties. We believe that the current mechanisms allow us to support third parties with relevant technologies to the high-pressure gas network.

221. In RIIO-2 we have had several third parties approach us both directly and through challenge setting activities. We have found a range of technologies both relevant and irrelevant. We believe it is important to ensure that the network consumers are not funding solutions that will not provide value to the UK gas network consumer and therefore have this as a key selection criterion in the selection process. We provide relevant feedback to ensure the reasoning behind not funding an activity is clear, this does however mean that some third-party solutions will not progress through the NIA and SIF process. We do attempt to support the third parties in finding an alternative route to delivery of their solution if required.

222. The following figure shows the partners involved in RIIO-2 projects to date and our proposed approach to further supporting SMEs and OEMs and we move through the remainder of RIIO-2 and into RIIO-3.

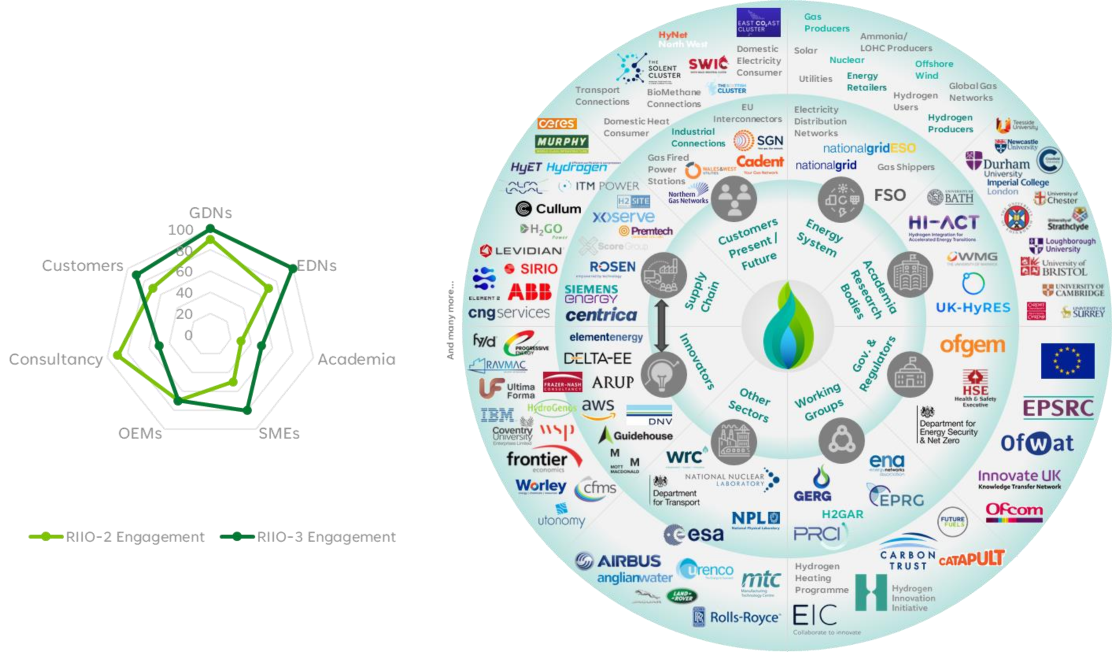


Figure 8

223. We are encouraged to work with 3rd parties through the NIA and SIF processes by the % of internal funding that can be provided to the network vs external parties. Through RIIO-2 our partner network has expanded dramatically due to the challenges we face with the energy transition and we will need to continue this in order to achieve our goals. Whilst we do need to increase the capability of our internal teams to enable the transition of our network, we also agree that we will need a large range of supporting 3rd parties and developing our capabilities together is vital. We have focussed on working with a broader range of third parties through RIIO-2 to develop a larger market to procure from in the future.

224. We would like to focus on developing our SME and start up partners further and providing improved support through to implementation. Whilst many of the solutions would be good for deployment on the network they may be too early in their deployment capability and production capability. Support for these companies to ensure they meet investment supplier assessments is key to moving technologies from innovation to implementation.

OVQ52. What are your views on us establishing an accelerator to support early-stage innovators?

225. The proposal of an accelerator is supported but requires knowledgeable assessment of the proposed projects for development. We have seen innovator projects shortlisted for network review that have little to no impact on the network in question. It is vital that projects are focussed on the energy network to make

them relevant to both the consumer funding the activity and the network to deliver the option into implementation. If this is not managed suitably the output will struggle to then be deployed onto the networks and the accelerator will be less impactful.

226. Innovators currently have the opportunity to develop their ideas through SIF and basecamp today, whilst these are useful mechanisms, we have found that actually a direct approach with ourselves has led to improved results. We propose that the networks are incentivised to do more direct challenge setting and engage third parties. Funding the networks to have resource for an innovation acceleration lead, whilst bringing together these leads from across the networks to support the accelerator would be more beneficial than relying on a 3rd party to decide what should be progressed.

OVQ53. What are your views on our proposal for this to be a smaller part of a future challenge fund and to be sponsored by networks?

227. We support the opportunity for third party led projects sponsored by the networks but suggest that the networks lead the activity as a cross network group to provide robust justification for the projects selected. The enablement of a cross network decision panel will prevent any one network from directing the decision based on network returns, whilst also ensuring that the projects have a path to deployment on the network. We will need to provide clear justification as to the selection as provided by UKRI on SIF projects.

228. The proposal for a larger overall fund to enable this added opportunity is supported and whilst we would hope that we are not preventing any relevant innovators from accessing NIA or SIF, this approach should diminish any external concerns regarding this.

OVQ54. Do you have evidence of potential innovation projects that have not been implemented or sought funding due to the five-year structure of the price control? How could this issue be addressed?

229. Innovation that is not funded by NIA or SIF does have little incentive if it spans multiple price controls or provides benefits in a different price control. This leads to business-as-usual innovation activities being focussed on lower risk, higher TRL activities. Whilst this is limiting, the application of NIA and SIF for those longer period higher risk activities balances out this impact.

230. The price control period does prevent engagement on longer term investments as the funding does not span across periods. This is being improved through the SIF fund which is delivered project by project. The majority of projects undertaken in RIIO-1 are being implemented through RIIO-2 with a few that will extend into RIIO-2. However, in the RIIO-2 period we are focussed on the energy transition and many of the projects being delivered could deliver results in RIIO-4 and 5. We have

made this clear in the CBAs for the SIF projects and is a part of our NIA value tracking.

231. NIA projects are more restricted to price control as the funding is managed across a price control, leading to long term engagement with universities for PhDs and interactions with industries such as the Nuclear industry being harder to undertake. At the end of RIIO-1 the networks were enabled to carry over live projects into the first year of RIIO-2, we suggest this provided for the transition to RIIO-3 also.

232. Providing an ability for innovation funding to be consistent year on year regardless of the price control period will assist in enabling improved collaboration whilst also preventing the ramp up and down of activity you see at the start and end of a price control period. We would be keen to identify a mechanism for projects with longer time spans (PhDs etc) to be funded. Engagement with universities is important both in terms of developing novel concepts but also in developing future talent for the energy networks.

233. Networks can request an NIA exemption request for NIA projects that span multiple price controls or do not meet the NIA criteria however this process is slow and not well known by the networks. Formalisation of the approach would be good for RIIO-3.

OVQ55. Do you agree with our proposal to run FRS trials with an explicit focus on informing changes to the rules governing energy network activities – incentivised through SIF or other price control mechanisms?

234. The proposed approach for the regulatory sandbox is a positive step in developing whole system demonstrations and NGT welcome the approach. We agree that the ERS and FRS should be progressed into RIIO-3 enabling networks to showcase the future in a real life environment.

235. Whilst we have not required the sandbox to date, our R2 SIF Beta proposal will bring together electricity and gas on a live network demonstration which will require a sandbox approach. We disagree that the networks are not pushing the boundaries of innovation far enough, the projects need time for development prior to entering a sandbox and should start to come to fruition later in the price control. RIIO-2 has provided a different focus for many of the networks and the first years have been spent doing more basic research and development tasks. Demonstration activities should accelerate as these projects come to their successful close.

236. The FRS sandbox directed by Ofgem could help identify where multiple projects could come together in a robust demonstration of the future network. NGT would be excited to support the identification and deployment of example future systems across a whole system approach. Whilst the networks share project proposals and activities it can be difficult to identify where there is potential cross over or touch points between projects, especially when another network is unfamiliar in its make up. We should help the network innovation teams to have a broader understanding of the energy system. The Summit is a good event to disseminate project work but doesn't provide that in-depth view of the network's challenges and approach. The

basecamp events have started to develop this but does not incorporate all innovation team members. A potential suggestion is an energy system training course that is common across all networks or an exchange programme between the networks.

237. We have also provided further feedback on the FRS through the “Call for Input on Proposal to introduce the Future Regulation Sandbox”.

OVQ56. What topics could FRS trials usefully focus on and why??

238. The FRS should focus on opportunities to demonstrate how the future energy system will work, with a focus on bringing collaborators from across the whole system together. Not just electricity and gas networks but water, nuclear, energy producers and users to demonstrate that our projects will provide the value they intend. Ofgem could help identify projects across the NIA and SIF mechanisms that have touchpoint that could be demonstrated, whilst also engaging other regulators to bring in other elements of the system.

239. The FRS could consider providing a sandbox for other regulations such as the HSE (GSMR). Whilst Ofgem have many of the regulations that will impact to future energy system, there are other regulators that should be involved in the sandbox to enable a robust demonstration to be undertaken.

OVQ57. Do you have any feedback on the view that not enough network innovation funded projects have been rolled out, and can you share any evidence you have to support your position?

240. NGT has had a focus on deploying innovations from RIIO-1 in the RIIO-2 period with £90.5m of benefits being delivered to date. We continue to progress our implementation activities with a potential to save up to £300m in total from the RIIO-1 portfolio. We shared our status on this in Feb 2022 (Consultation on the closeout methodologies for RIIO-GT1) and have continued to use the format provided for this RFI to track our delivered benefits to date.

241. As mentioned in previous questions we track value of our projects from idea selection through to deployment. Once a project is completed, we support the business in transitioning the technology into implementation, providing training, policy updates and other relevant steps to move to TRL9. Once we have tracked the project into delivery we select a time period for benefit delivery, for instance 5 years, each year we will review the benefits delivered and log these. Once we are happy, we are seeing a consistent benefit back to the business we publish the case study on our website. www.nationalgas.com/innovation-value-tracking.

242. We plan to continue this for all RIIO-2 projects. Whilst the playbook is looking at specific project delivery in RIIO-2 we do not believe this will provide a robust view of the value tracking activity undertaken to date in RIIO-1 projects. We have also not been asked to provide insight into our value tracking process only an example project.

243. Regarding RIIO-2 project implementation, whilst it is feasible to deploy innovations in one price control from the previous period, delivering benefits within the same price control period is highly unlikely especially in light of the energy transition focus in RIIO-2 and the networks not currently being able to transport hydrogen or other net zero gases.

244. As above we plan to continue to follow the same value tracking process deployed to date for the RIIO-2 projects both NIA and SIF funded. We are also looking at taking learning from prior value tracking activities to improve our accuracy of value estimation at the start of projects.

OVQ58. What are your views on the design of potential new mechanisms to address this?

245. Value tracking within NGT has a robust process. Through the GIGG working group we review projects that could be shared and deployed on each other's networks.

246. The supporting test addresses Ofgem's potential new mechanisms to improve deployment of innovation in the following areas:
   a. Late-stage incentive for demonstrator projects tied to successful demonstration of business as usual implementation:
   b. A roll-out allowance:
   c. Penalties:
   d. Performance based incentives:

- **Value tracking within NGT has a robust process to ensure value is delivered back into the business from the innovation project activity**. Through the GIGG working group we review projects that could be shared and deployed on each other's networks. In RIIO-1 we held an implementation and inspiration log that enabled the project sharing to be easily tracked, we have been reviewing a method to optimise this approach in RIIO-2 across the gas networks and wider electricity networks.

  NGT is the only Gas TSO in the group and many of our projects do not translate across to the GDNs, we do however believe this is not a reason to be a part of the discussion. The GIGG working group in RIIO-2 has been focussed on encouraging other gas networks to partner on projects that are likely to be of interest even if they are not financially involved, this early buy in and ability to steer the project makes it more likely that the other network will deploy the outcome.
- **Late-stage incentive for demonstrator projects tied to successful demonstration of business-as-usual implementation**
  An incentive to take on the risk associated with innovation deployment could support the innovation team in progressing projects into business as usual. At present investments are not always willing to accept the risk of implementing an innovation project when already struggling to deliver their programmes to time, quality and cost.

- **A roll-out allowance**
  NGT would welcome the opportunity for a similar fund to the NIA to support the activities between innovation project close and deployment, such as policy update, training and extrapolation/scale up of the solution. One limiting factor to the speedy deployment of projects is the time it takes to attain business funding to undertake these activities and or build them into the already packed schedule of the business teams.

- **Penalties**
  NGT aim to deliver 4:1 benefits from their innovation portfolio in a price control in the following period. We do this without the need for incentives or penalties as it is the right thing to do and important to maintain the innovation funding in future price controls. It is important to note that innovation is risky and not every project will successfully deploy a solution into the business. It should also be noted that activities tend to progress through research, deployment, demonstration and then implementation. These stages could be made up of multiple projects. For this to be reasonable the approach should only be considered for projects that enter the demonstration phase.

- **Performance based incentives**
  As above we deliver value for the consumer through deployment without incentives or penalties and whilst we think that a roll-out allowance could support in accelerating the roll out of projects into business as usual we believe the networks should be actively working in this space already. Incentives could improve the business support for the introduction of innovation into business as usual.

Data & Digitalisation

OVQ59. Do you have any views on the timelines for modernising regulatory reporting?

247. We are keen to modernise and automate the regulatory reporting process as much as possible. This is currently process and resource intensive, so it is in all parties' interest to modernise and automate where possible. We understand that the RRP table structures and inputs will change under RIIO-3 so we are cautious about regret spend and investment under the RIIO-2 format. However, this does not preclude doing work to analyse, map and prepare automation now.

248. Some of the key areas that we need to consider include:
  a. Automation of the internal processes to produce RRP and;
  b. Automation of the submission, communication / systems between Networks and Ofgem.

249. Of these key areas, the challenge with the latter is without improvements / high confidence automation of the internal process, then there is limited value to networks while accepting that there could be for Ofgem and consumers.

250. In relation to point (a) regarding internal RRP data automation, this could be more challenging to deliver given the entire scope of the data in question. In addition, data often needs interpretation to ensure it is providing the information to meet the RIGs and given that data is currently held is numerous complex systems, designed to ensure that SO & TO functions work efficiently, this doesn't always lend itself to reporting efficiency and therefore we will need to carefully consider the most efficient way to mitigate these challenges.

251. We are putting effort and investment into the data preparation process so that we can understand bottlenecks, identify manual steps that could be automated and address data quality issues. These activities are key, irrespective of RRP processes, so it is of benefit to progress with these areas of focus. We are currently doing analysis of all RRP tables, and we look to have a plan and approach set out next year. Our initial focus will be on systematically working through addressing quick wins and putting together detailed plans to decompose more complex metrics.

252. We are keen to work with Ofgem to set the standards for the technology and method through which we could share or expose the data.

253. We plan to finalise and complete the modernisation over the course of RIIO-3 and therefore the timeline seems reasonable.

OVQ60. Do you have any initial views on opportunities for improving efficiency in providing the data that Ofgem receives as part of regulatory instructions and guidance?

254. As we are currently in the initial phases of the analysis process, we do not yet have a view on opportunities for improving efficiency but view that any savings in terms of manual effort and improvement of data quality will be the areas targeted during the process.

OVQ61. Are there areas of regulatory reporting that would be most beneficial to start with in the modernising project?

255. We will have a more defined view in the coming months of which area will most benefit and how to best sequence the approach to automation of our internal RRP preparation. However, areas such as TOTEX, CAPEX and Unit Cost data which require multiple inputs should be streamlined and simplified in the data preparation steps so that manual processes are removed. Areas where we are dependent on third parties is also something we wish to explore such as carbon footprint which can be manually intensive to collate the data.

256. Other targets such as simple tables using one source are good places to start to test methods of automation and sharing but this will be looked at as we prepare our plan and complete the analysis next year.

NGT Response: GT Annex

Infrastructure fit for a low-cost transition to net zero.

GTQ1. Do you agree with our proposal to include a re-opener to manage the impact of introduction of the CSNP and gas strategic planning processes, with annual windows starting from the first year of the price control?

1. We agree that the proposed re-opener would be of value and should also reflect the need to potentially respond to the regional energy strategic planner (RESP). Although the strategic nature of the NESO's planning role is likely to mean that investments will be identified in longer timescales (Y+10 and beyond) it is possible that these could be substantial in nature and may take many years to develop and deliver. The proposed re-opener would mitigate the risk that any conflict in timing between the point of their identification and an opportunity to include them in the regular price control process could cause a significant delay in delivery and cause unnecessary costs to consumers.

2. Given the potential for rapid developments in net zero policy / strategy during the course of RIIO-3 it may be prudent to broaden the scope of the proposed re-opener to encompass a wider range of changes in circumstances. For example, it could reasonably be envisaged that the Government's interim strategic planning role for hydrogen could have knock on impacts from a natural gas perspective.

3. As we outlined in our response to Overview Q1, a reopener looking to take account of potential developments in gas strategic network planning needs to be agile and flexible. As such, we would suggest that the annual window proposed should be replaced with **a more flexible trigger timing** which allows for a broader set of external triggers to be acted upon at pace.

GTQ2. Are there any other areas of our proposed RIIO-3 framework (eg outputs or UMs) that you think may need to adapt to accommodate the future role of the FSO in strategic network planning?

4. There is a likelihood that the role of the NESO continues to evolve beyond day 2, and this may have consequential impacts on the roles and accountabilities required from network companies linked to CSNP or RESP process which are not yet fully developed. It may therefore be prudent to consider a UM to adjust the allowed revenues of affected network companies to fund the delivery of additional activities (capex or opex) to support these revised roles and accountabilities.

5. It is important the package of uncertainty mechanisms are sufficiently broad as to accommodate emerging outputs from the NESO. This could involve resilience-based activities (which could be picked up by the new resilience reopener), net zero activities (which could be picked up by the net zero suite of mechanisms), whole

system adjustments across networks (which could be covered by the Coordinated Adjustment Mechanism) or it is feasible that all of these could be picked up by the newly proposed Gas Strategic Planning reopener. Fundamentally what is important is that the range of uncertainty mechanisms enable flexible and agile action following any relevant trigger. We are less concerned about the potential overlap in mechanisms and more concerned with ensuring the full suite of potential uncertainties are accounted for. As stated in our response to GTQ1, this is unlikely to be achieved through strict annual windows for any of these mechanisms.

GTQ3. What are your views on what the overall focus of the RIIO-GT3 environmental package should be, and should any additional areas be incentivised?

6. Overall focus of the RIIO-GT3 environmental package should encompass all relevant aspects of environmental activities and be cognisant of future legislative and reporting obligations.

7. The package should recognise the Glidepath to Net Zero (building on current BCF reporting), Climate Change Risk and Adaption, Circular Economy, Sustainable Procurement, Nature Based Solutions and Nature Risk.

8. There are additional areas that we have also identified that could be considered as part of the broader Environmental Package. In our response to OVQ15, we said that low-carbon connections can have multiple wide-ranging benefits and supports the Government's energy security agenda by diversifying the sources of gas and in OVQ37 we also said that this will also help to unlock more opportunities within the market to increase biomethane production and support Government ambition of 30 – 40 TWh of biomethane production by 2050, which Government has said would help the UK achieve net zero cost effectively.

9. We also expect that biomethane as a clean gas will become more prevalent across many of the European Union countries that we trade with, given the EU's ambitions to reach production target of 35 billion cubic metres (bcm) per year by 2030 set out in REPowerEU action plan[14] which creates further opportunities.

10. However, biomethane uptake in the United Kingdom has been relatively slow for a range of reasons and we believe that the NTS can play a more significant role in helping to unlock an increase in uptake and help facilitate Governments Net Zero ambition. We have provided accompanying evidence[15] with this response setting out our views on why there is a need and how the NTS can step in to play an important role in facilitating biomethane production in the United Kingdom. This could equally apply to hydrogen blending once a government decision is made.

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[14] European Union, (May 2022), REPowerEU, Scaling up Biomethane: EUR-Lex - 52022DC0230 - EN - EUR-Lex (europa.eu)

[15] National Gas, (March 2024), Biomethane Connections SSMC: Facilitation of Connections to the NTS – Paper attached in email.

GTQ4. What are your views on each of the current individual environmental outputs presented in this section and the Overview Document?

NGT EAP and AER

11. We agree with Ofgem's proposal to retain the EAPs and AERs in RIIO-3. The EAP provides a framework for NGT to monitor progress and helps to drive behavioural changes. The AER provides the mechanism for reporting on our progress which meets stakeholder and customer requirements. Our customers want to see that we are delivering against our targets and minimising our environmental impact.

12. The proposal for the new AER format with commentary and KPI table is welcomed. This approach would provide a consolidated data table rather than the current reporting format which consists of a KPI table and various other figures detailed throughout the report. This approach should be more efficient and would enable comparability across the networks.

Environmental Scorecard

9. NGT would welcome the withdrawal of the Environmental Scorecard and the proposal to incentivise through the Annual Environmental Report. The Environmental Action Plan/Annual Environmental Report are a duplication of the Environmental Scorecard elements and thus the proposal would help drive efficiencies.

Greenhouse Gas Emissions – see GHG ODI Response GTQ5

10. We believe the current RIIO-GT2 GHG emissions incentive scheme to incentivise NGT to reduce the amount of natural gas vented from our compressors provides the right level of focus to encourage us to seek innovative ways to reduce the effect of our operational activities on the environment and should be retained with recalibrated parameters. For further details on the incentive see section GTQ5.

NTS Shrinkage – see Shrinkage ODI Response GTQ7

11. We believe the current RIIO-GT2 Shrinkage and emissions incentive scheme to incentivise the efficient procurement of Shrinkage costs should be returned to a financial incentive based around the purchasing price of the NTS Shrinkage gas requirement (as prudent risk management of costs). For further details on the incentive see response to GTQ7.

Redundant Assets

12. We anticipate that our RIIO-3 plan will seek allowances for removal of further redundant assets, for example assets rendered redundant in the RIIO-2 period. As such we believe there remains a role for this output. See further details in response to GTQ10.

Compressor emissions

For the treatment of compressor emissions PCDs and re-openers see responses to GTQ11 and GTQ12.

GTQ5. What are your views on the above two options for the GHG emissions incentive?

Option 1: Retain the output but as an asymmetrical financial incentive, with a larger cap than collar and a more stretching target. This would encourage NGT to continue to make further improvements to optimise the venting processes to the fullest extent possible; and

Option 2: Returning to downside only incentive, embedding historical performance and a more stretching target. This option assumes that reduced GHG emissions below the target should be considered business as usual and that only underperformance would be penalised.

13. Venting emissions are externalities that we would, in the absence of an incentive, not incur a cost for. Fundamentally, the aim of the GHG incentive is to internalise these externalities, so that our decisions appropriately reflect the cost to the environment. Consumer value is driven by a reduced level of carbon emissions, i.e. a reduced socialised 'cost'.

14. We believe that Option 1 to retain the incentive, with a recalibrated symmetrical reward and penalty, would continue to deliver the best option and further encourage us to identify and make innovative improvements to reduce our controllable compressor venting activities. There is material additional value to be had for customers and society by providing the incentive for us to seek improvements as well as to be penalised for underperformance (i.e. both a carrot and stick approach).

15. In contrast, we believe that Option 2 to return the incentive to a downside only scheme will not drive the right behaviour and limit our ability to take beyond business-as-usual initiative actions.

16. In either case, in order to set targets, we believe embedding historical performance into the allowance should be equally as important as forecasting future flow patterns as increased volatility will provide additional challenges in our ability to reduce compressor venting. We note that RIIO-GT1 past underperformance against this incentive shows how challenging the target can be.

17. We have been successful in identifying compressor venting initiatives and projects to support the reduction of emissions and improved our performed well under the RIIO-GT2 scheme. Therefore, the incentive has been successful in improving our performance and leading to GHG emissions reductions for the ultimate benefit of society and UK. Continuing and increasing this scheme will support our focus on new projects and initiatives to reduce venting emissions.

18. We can demonstrate our activities that support improved performance, from new monitoring tools to behavioural and procedural changes, alongside system and project improvements.

19. Whilst our venting performance has generally improved over the past 5 years, a recalibration of targets will allow for a review of past performance alongside future expected flow patterns, maintenance, and other venting activities such as commissioning new units. The target allowance should recognise the need to run compression to avoid entry or extremity constraints, support increased linepack flexibility and maintenance activities by moving gas into other feeders, and supports asset health and legislative emissions testing, alongside running the NTS system.

20. A decrease in overall demand will have limited impact on compressor running hours and vented emissions, with increasing summer flows providing additional challenges to our ability to use all the initiatives we have available in the summer maintenance period to reduce venting.

21. When setting the target allowance, it will be necessary to recognise the base level of venting required and changing flow patterns affecting our ability to use all our initiatives to drive performance while maintaining the strength and integrity of the incentive.

GTQ6. What improvements to the incentive would continue to minimise NGT's impact on the environment from venting?

22. The investments under the Net Zero Pre-construction and Small Net Zero Projects Re-opener (NZASP) uncertainty mechanism for methane emissions reduction will help identify and support minimising our emissions from operating the NTS. If the compressor machinery train vented emission reduction trials are successful (due to start in 2025), we expect to propose further roll out of these solutions in RIIO-GT3.

23. The implementation of compressor machinery train investment will help capture and further identify opportunities to remove methane losses from our operations.

24. The GHG Compressor emissions incentive is very specific to reducing emissions from our compressors, we believe this focus on reducing our operational emissions could be further strengthened with the introduction of an additional emissions incentive to reduce the amount of natural gas vented from our pipelines.

25. We are not currently incentivised on any pipeline venting reduction activities, venting in this area contributes ~15% of our operational emissions.

26. During our pipeline maintenance, where practical we will recompress gas within the pipeline to ~7/8bar and vent (release to atmosphere) the remaining gas as we currently have no ability to recompress gas under this pressure.

27. During 2025/26 we will receive delivery of the funded new mobile recompression units which will further reduce venting to ~1bar, an incentive should be designed to encouraged prudent management planning and utilisation of these newer recompression rigs to optimise venting reductions.

28. Optioneering of planning schedules to recompress previously vented methane from ~7/8bar to ~1bar, has the potential to save approximately 500+ tonnes per year from this currently un-incentivised activity, this is a similar saving in the compressor emissions incentive.

GTQ7. What are your views on the above three options for the NTS Shrinkage incentive?

Option 1: Continue with NTS Shrinkage as a reputational incentive.
Option 2: Reintroduce NTS Shrinkage financial incentive but with a collar and a cap that is proportionate to the annual shrinkage costs.
Option 3: Introduce a financial incentive for the UAG and CVS components. This option explicitly focuses on UAG and CVS as the two components with increasing volumes of shrinkage gas and the underlying reasons behind that require further investigation and mitigation.

29. We agree with Ofgem's proposal for Option 2, and the reintroduction of NTS Shrinkage financial proposal.

30. We believe that the current reputational incentive could be replaced with a new financial incentive to sharpen our focus on reducing costs to consumers in a significant area of operating expenditure, while continuing to maintain an appropriate attitude to risk in increasingly volatile markets.

31. We do not believe that a financial incentive for either UAG or the CVS volume components of shrinkage is appropriate as these elements are outside of our control.

32. To return to a financial incentive we would propose to continue to utilise a mixture of Forward and Prompt trading products. These act as an appropriate risk management tool to help manage shrinkage costs that could be affected by sudden changes in market fundamentals. This thinking is in line with the 2018 Ofgem State of the Market report which talks about the GB Wholesale Market indicating "a high level of forward market trading activity which should support competition in the retail markets by enabling suppliers to smooth purchasing costs".

33. We propose the re-introduction of caps / collars tied to a performance measure, with sharing factors applied.

34. We believe that purchasing Forwards and Prompt volumes with an even profile for each product, in a market in which we are unable to accurately predict prices and one with large price movements, is a sensible risk management approach that provides a good level of cost certainty to consumers.

35. Although leaving costs to cashout would appear to be attractive if prices fall, it's just as likely that that costs rise on the prompt. Where we leave procurement to

within day this may require residual balancing actions which may increase cashout / prompt prices and therefore imbalance and consumer costs.

36. The over-arching principle of our proposal is that we should be incentivised on activities which we have a level of control and influence over i.e we have control over when we trade not volume.

37. Licence restrictions prevent us from speculating on the wholesale market i.e we are BUY side only (selling back of volumes is permitted for balancing closer to delivery once there is increased certainty of volumes) meaning we are unable to undertake hedging transactions to offset risks. Therefore, we have “one shot” at each transaction with the aim of keeping costs as low as possible.

Observations on Option 3

38. Retaining the obligation to investigate and report on the causes of UAG, one of the components of NTS Shrinkage, this obligation and associated report is in effect a reputational incentive.

39. We have minimal control over levels of CV shrinkage which occurs where the CV directly entering the DN from their entry points (primarily biomethane) has a greater than a 1 MMJ difference to the gas entering the DN from the NTS. As such CVS is dependent on gas quality into the DN from both direct DN supplies and NTS supplies neither of which are within our control. We do try to reduce this impact via configuring the network to minimise CVS where we can, but this is limited. Therefore, based on all of the volume elements being outside of our direct control a volume incentive is not appropriate.

40. Based on the above we propose to retain the UAG monitoring and reporting obligations and continue to seek to further improve our data visualisation tools and investigate projects to further identify the causes of UAG.

GTQ8. What are your views on reviewing the way the GSO costs, including costs for procuring NTS shrinkage gas, are forecast and recovered?

41. Shrinkage costs, being primarily made up of gas procurement costs, were significantly higher than forecast for 2022/23. This was primarily driven by inflated wholesale gas prices following the Russian invasion of Ukraine, as well as higher than forecast shrinkage volumes, in part due to increased throughput and increased compressor use to enable high exports to Europe. The drivers behind these price and volume increases were not factors within NGT’s control nor were they reasonably foreseeable given the geopolitical events that led to them.

42. Whilst the existing methodology provides for an annual forecast to be re-opened to latest prices should the impact be material (currently defined as 10% of Allowed Revenue), this opportunity is limited to a relatively short timeframe and leaves NGT exposed to future cost increases and the network user’s potential suffering a delay to cost reductions should cost forecasts drop.

43. Furthermore, market movements were significantly higher and over a much shorter period than had been encountered in recent years. This resulted in NGT incurring significantly higher costs [total NTS shrinkage costs for 2022/23 were £682m, over three times higher than for 2021/22] and suffering a delay in recovering what are passthrough costs as defined in RIIO-2.

44. Existing methodology only allows reforecasting (to be updated into revenues and therefore charges) if the republication criteria is met (3% or SOAR?). This, by itself, does not fully address or reflect the challenges and exposure of the gas prices and external factors on the overall cost and the timeliness of its recovery. It also does not address the impacts of reconciling costs and the timing of this in reconciling charges to Customers.

45. NGT is exploring the possibility of recovery of shrinkage specific costs closer to when they are incurred. In addition to these industry discussions which may result in a UNC change proposal we welcome the potential to review this particular component of the Allowed Revenues or wider as would be needed, on the updating of forecasts within a Regulatory Year (that would therefore adjust Allowed Revenues) and the option to update charges to reflect any material updates.

46. Therefore, there are ongoing discussions with [Ofgem and with Industry through the UNC Workgroup NTSCMF (NTS Charging Methodology Forum)] to adjust the charging mechanism for shrinkage costs to enable more agile change to charges for shrinkage costs that would significantly shorten the timeframe between costs changing and such costs being reflected in prices charged to network users. [To consider impact on risk profile in cost of debt].

GTQ9. What are your views on including NTS Shrinkage costs within NGT's baseline totex allowance?

47. As described in the response to question GTQ8, NGT has very limited control over the principal drivers of these costs, being shrinkage volumes and market prices. It would therefore be wholly inappropriate to include these costs within NGT's baseline totex allowance.

48. Furthermore, given the manner in which shrinkage costs are incurred, inclusion in baseline allowances is likely to require a significant change to the mix of fast and slow money allowances in each year of RIIO-3, introducing an administrative burden without an obvious benefit to the consumer when consumer benefits are more likely to be secured via a well-calibrated incentive.

GTQ10. Do you have any views on the future of this PCD? [redundant assets]

49. We anticipate that our RIIO-3 plan will seek allowances for removal of further redundant assets, for example assets rendered redundant by virtue of customer disconnections in RIIO-2, or otherwise no longer required to meet network

capability. We are unsure if this requires a PCD given the lower volume of work, therefore could be more appropriate to be picked up as part of the Asset Health.

GTQ11. Do you have any views on the proposed removal of this re-opener?

50. We are currently trialling DLE retrofit technology to assess suitability for our Avon fleet to comply with emissions legislation. We will need to engage with Ofgem further on appropriate funding mechanisms should a rollout of this technology be suitable (pending results of the trial). This may result in the need to retain the Compressor Emissions re-opener. We should look to explore options on how to deal with compressor emissions that would remove regulatory burden for both Ofgem and NGT, which could be to retain the mechanism or set allowances if there is suitable cost and scope certainty.

51. There is also potential that we will require a re-opener for other compressor works, which is expected to be driven by resilience, along with emissions compliance.

GTQ12. Do you have any views on the above proposed PCD for RIIO-GT3, including on the Hatton PCD and on baselining compressor emission costs for the next price control?

52. We agree with Ofgem's proposal to maintain PCDs for the compressor emissions sites where Ofgem have agreed the Final Proposed Options as part of the RIIO-GT2 price control (this includes St Fergus, Wormington, King's Lynn, Peterborough and Huntingdon).
53. The re-openers have not yet been submitted. Following submission and subsequent Ofgem direction, the cost uncertainty for the final selected option should be resolved, along with an update to the PCD within licence condition 3.11 to reflect the work required throughout the RIIO-GT2 and GT3 periods.

54. In principle, the allowances and associated PCDs will be set following NGT's re-opener submissions with delivery of the approved options in RIIO-GT3.

55. We agree that the PCD for Hatton will no longer be required in RIIO-GT3 as delivery will be completed in RIIO-GT2.

56. As part of NGT's Business Plan we might be requesting funding for RIIO-GT3 in regards of other compressor sites to comply with the Medium Combustion Plant Directive (MCPD), which were not part of the RIIO-GT2 PCDs/re-openers (see response to GTQ11).

GTQ13. Do you have any views on whether the ANCAR will still be required as an output in RIIO-GT3 and on its need for RIIO-GT2 business planning?

57. Our understanding is that the ANCAR will be removed as a licence obligation on NGT, as indicated by discussions to date and the draft licence amendments released by Ofgem on 14th December.

58. This will not prevent NGT from creating and publishing its own analysis in support of RIIO-GT2 business planning, submissions into the RIIO-GT3 process or more generally information which NGT may want to share with the industry on asset developments, network performance and system capability.

GTQ14. Do you have any views on the effectiveness of this PCD [Asset health – non-lead assets] PCD?

59. As Ofgem recognise, in RIIO-GT2 the majority of NGT's asset health plan work that is necessary to maintain the safety and reliability of the network was covered by NARMs. The remainder (work such as civils and electrical investment) was covered by the non-lead asset PCD. Non-lead assets are excluded from NARM as they do not have easily measurable, or have non-existent, relationships between condition and/or age and the likelihood of failure. Examples include, security fencing or pipe supports, where the relationship between a poor-quality asset and a measurable service risk consequence is highly uncertain.

60. For RIIO-T2 the non-lead asset PCD set specific volume or other outputs targets.

61. NGT believes that we need to retain the non-lead asset PCD for RIIO-GT3 as non-lead assets will remain outside of NARM.

GTQ15. Do you have any views on our proposal to remove the Bacton re-opener mechanism but retain the PCD?

62. The Bacton terminal redevelopment FOSR and re-opener applications have not yet been submitted. Following submission and subsequent Ofgem direction, the cost uncertainty for the final selected option should be resolved, along with an update to the PCD within licence condition 3.10 to reflect the work required throughout the RIIO-GT2 and RIIO-GT3 periods (and potentially beyond).

63. In principle, if all required funding is provided for the RIIO-GT3 period, the removal of the re-opener with a retained PCD for the Bacton terminal redevelopment would be an acceptable proposal. However, this is uncertain until the resolution of the current re-opener. Any funding required beyond the RIIO-GT3 period could be included in future regulatory business plan submissions.

GTQ16. Do you have any views on this re-opener [King's Lynn subsidence Re-opener and PCD]?

64. We support Ofgem's position: Namely that the King's Lynn output has been delivered in RIIO-2. Therefore, we see no reason to continue the King's Lynn subsidence PCD or re-opener in RIIO-GT3

GTQ17. Do you have any views on our options for the Customer Satisfaction Survey Incentive? In particular, do you see merit in recalibrating target performance to NGT's most recent performance?

65. We are minded to agree with elements of Option 1; recalibrating the target by taking into account the previous 5 years of performance data, we agree that the target can be recalibrated to drive further improvements and build on customer-centric behaviours we have developed over the current and previous price control.

66. We are unsure of the benefits a narrower cap/collar would provide. In our experience, the level of performance is strongly linked to the investment required activities. Without appropriate rewards, it is less likely we will be able to improve and deliver better outcomes for our customers and end consumers. An achievable target would allow for innovation and investment to maintain and further develop our approach resulting in improvements in our customer-focused service and experience.

67. In our continuous effort to strive for improvements, we are exploring new metrics to deal with an increasingly complex consumer environment which we will test and refine with our customers.

68. The current approach to gather a numeric score after customer interactions and in addition obtain qualitative feedback to make improvements, is an approach that still has value to the business in terms of recognising areas of improvement, and ultimately customers benefit from the efficiencies created by the improvement actions.

69. This enhances customer value by fostering positive relationships, improving reputation and reducing dissatisfied customers leading to long-term benefits for the customer including operational efficiency. Although we agree that the target can be recalibrated, we recognise that this target needs to be achievable, in order to not adversely affect consumers through lack of investment in our customer-focused approach.

70. We aim to work with Ofgem and stakeholders to develop and refine the metrics around this incentive to ensure we are taking a customer-centric approach.

71. We disagree with a penalty only option, or any considerations regarding introducing asymmetry to the incentive value as this would significantly reduce the amount of action we would be able to put in place, to continue to drive improvements for our customers. This would shift us from being able to drive significant improvements, and not incentivise us to drive the right behaviour. Removing the financial incentive, would drive a similar outcome, in that would not allow us innovate, drive significant improvements and could cause performance to inadvertently stagnate.

72. Option 1 would allow us to embed the great customer service we have strived for since its introduction, combined with exploring new metrics to deal with an increasingly complex consumer environment. The future landscape becoming more uncertain further affirms that it is essential for NGT to continue to engage with customers in order to share our knowledge to aid informed customer decisions, work in an agile manner to adapt to customer needs in a changing environment and thoroughly analyse the insight we have to create new efficient processes.

GTQ18. Do you have any ideas how the strength of the incentive and the range between capped and collared outcomes should be set?

73. We agree that the target and cap/collars should be re-calibrated informed by our RIIO-GT2 performance however, whilst the target needs to be stretching, it also needs to be achievable, which drives the right behaviours.

74. In relation to having a narrower cap/collar, we would question the value it would bring of reducing the existing ranges, We propose the cap and collar distance remain the same, in our experience, the level of performance is strongly linked to the investment required activities. An achievable target would allow for innovation and investment to maintain and further develop our approach resulting in improvements in our customer-focused service and experience. We will also test possibilities with our stakeholders for this incentive before making a decision.

75. In our experience, the level of performance is strongly linked to the investment into a wide variety of offerings, services, and tools. Without appropriate rewards, it is less likely we will be able to improve or deliver better outcomes for our customers and end consumers.

GTQ19. Which new touchpoint areas could be added to the incentive, and which new engagement and survey channels could be introduced to help NGT improve in the delivery of its services to customers?

76. We are exploring several new initiatives directly related to the customer journey to cover with additional touchpoints and to improve customer/consumer needs in a highly volatile environment.

77. These metrics may include turnaround time (Application To Offer), percentage difference in cost estimation versus final costs, and measures accelerate connections buildout. However, further work must be done to assess the feasibility of such metrics including number of data points, intentionality of metric, and value case/feasibility for target and cap/collar.

78. We will be engaging with Ofgem and industry to further identify which process areas would be most beneficial to customers for us to focus for possible additional

metrics. We are taking a customer-centric approach through engaging with customers ensuring we are hearing first-hand where potential improvements or efficiencies can be made to most satisfy the customer.

GTQ20. Do you have any views related to the transparency of the customer survey results?

79. We are happy to remain transparent in our CSAT results within the GDPR guidelines and have detailed breakdowns of the data if so required.

80. We will work with Ofgem and our stakeholders to understand what detail would be useful and explore what is possible. Breakdown of the data such as survey areas, volumes and additional analysis including response rates can all be made available from the company and from the survey provider.

GTQ21. Do you have any views on how positive changes in NGT's behaviour and customer service could be incentivised?

81. We see this as an opportunity to explore other areas of incentives in the behavioural space, in particular we see the potential for value from a Whole System incentive providing value to industry and consumers, which we provide more information on in answer to OVQ15.
82. The new initiatives mentioned in the answer to question GTQ19 can be tailored to ensure that they incentivise positive changes in customer service and we will continue to consider the most appropriate way to do this.

GTQ22. What are your views on our proposal to remove the Stakeholder Satisfaction Survey reputational incentive?

83. In principle, we agree with the proposal to remove the Stakeholder Satisfaction Survey incentive. Stakeholders provide valuable feedback to NGT and are a crucial part of our engagement plans and driving improvements, however we recognise that this can be continued without needing to be incentivised reputationally.

84. We will continue to survey and drive stakeholder satisfaction but see this as an opportunity to explore other areas of incentives, such as a behavioural incentive on how the Whole System can be facilitated, so as such are minded to agree with the proposal to remove the Stakeholder Satisfaction survey.

GTQ23. What are your views on our minded-to proposal to retain D-1 Quality of Demand Forecasting incentive as a financial incentive with a tighter target?

85. We agree with Ofgem's minded-to-position to retain D-1 as a financial incentive.

86. We disagree that the target should be tightened considering the recent and predicted gas demand volatility (see 89). Scheme parameters need to be recalibrated to reflect the changing market dynamics and adjusted appropriately, both in terms of base target, as well as the level of adjustment made to it (i.e., in the event that certain sources of volatility increase over the price control period).

87. The level of improvement possible will be, to an extent, linked to the investment we make in new models, third party data, forecasts we procure from external providers, market intelligence and staff development.

88. We support Ofgem's minded-to-position to retain the D-1 demand forecast as a financial incentive. In RIIO-GT2 our customers told us that an accurate day ahead demand forecast is likely to lead to savings for consumers. This is because an accurate forecast should reduce the number of occurrences where shippers incorrectly anticipate the level of demand on any given day. The absence of an accurate demand forecast therefore has the potential to increase costs in the market and therefore for consumers (assuming increased costs are passed on to consumers). An accurate forecast should support the minimisation of occurrences where shippers are forced to either procure additional gas to meet unanticipated demand, potentially at a higher cost, or sell surplus gas, which may be at a lower price than originally procured or be exposed to imbalance cash out charges.

89. Our day ahead demand forecast also supports the market as it helps to create a level playing field i.e., customer feedback suggests that the larger shippers use the forecast we provide to validate their own forecasts whilst the forecast supports smaller shippers by giving them an alternative to incurring costs in procuring their own forecasting capability. In essence, it provides the whole market with a view of demand at the same time and by doing so creates a fair opportunity to procure gas accordingly.

90. Whilst we agree that the D-1 financial scheme should remain, we don't agree that the assumption of tighter target within the question is the correct approach. However, we do agree that the scheme parameters should be reviewed and potentially recalibrated in order to reflect the changing market dynamics seen since the calibration of the RIIO 2 scheme. We consider that as part of the reassessment of the scheme the base target as well as the level of adjustment made to it (i.e., if sources of volatility increase over the price control period) should be in scope.

91. As we move through the remainder of RIIO2 and into RIIO3 some of the market fundamentals are likely to remain uncertain. In recent years we have experienced an unforeseen number of events that impacted the energy market. Due to Covid and the Russia-Ukraine war we have seen a reduction in Industrial load. Furthermore, the energy price crisis has led to reduction in domestic consumption (linked initially to Suppliers failing in GB and more recently, with a bigger effect, to

the impact of Russia / Ukraine war). The Russia / Ukraine war also impacted exports to Europe with GB facilitating c20bcm of gas export in summer and autumn 2022 contributing towards the maximum storage stock of c100bcm in Europe as a result of approx. 80% reductions in Russian supplies. All of these events created challenges in generating accurate forecasts and led to continuing upwards pressure on the level of volatility in gas demand at the start of RIIO-GT2.

92. The existing storage adjuster accounts for volatility in terms of any storage capacity growth and, considering the importance storage will play in security of supply in the future, we believe it should remain part of the scheme. This is further justified by recent unpredictable behaviour of storage operators who, driven by price volatility, not only inject gas in the summer and withdraw in winter, but more frequently deviate from that seasonal behaviour. This impacts on gas demand and our ability to predict how storage will act in volatile market conditions.

93. It’s also worth noting that our ability to create an accurate forecast is dependent on the accuracy of the input data we receive that is utilised in our processes and models e.g., price data at the time of forecast for the following day for both power and NBP/TTF and ZTP hubs, the Composite weather variable (CWV), or the wind forecast from Electricity System Operator (ESO). All of these have a direct impact on our forecast accuracy.

94. Whilst we look to evolve and improve our models if purely assessed on the outcomes from the demand forecast incentive and the expected potential profit opportunity, it is challenging to generate a business case for significant investment which may result in a step change in performance.

95. As the market has evolved based on the events described earlier, we have sought to improve our models during RIIO-2 with a primary focus on power, however we have not seen a step change in performance from these models. This could be for a number of reasons; for example, data provided by third parties - we know that renewable intermittency creates volatility in gas demand for power as do price changes which occur after the submission of our forecast.

96. We have also spent a lot of time evolving our processes to adapt to the changing market dynamics. For example, due to the increase in LNG delivered to GB we have increased our focus on LNG supply and local weather forecasts at the LNG terminals (the local weather forecast for a given day can have an impact on supply from LNG terminals due to the effect on docking conditions which in turn has the potential to affect demand).

97. Fluctuations in demand can be unpredictable and volatile, making it challenging to forecast accurately. External factors such as economic conditions, market trends, competitor actions, and consumer behaviour can significantly impact demand patterns. Rapid changes in customer preferences, emerging technologies, or

unexpected events (e.g., political disruptions) can further increase demand volatility and uncertainty. It is our view that, considering the rapidly changing market conditions and UK's net zero ambition, no decline in our demand forecasting performance should be perceived as a continuous improvement.

98. Furthermore, we have witnessed other areas where volatility has increased, and we expect this will continue. For example, the renewable wind capacity available has increased since 2019 and we expect the renewable capacity available on the power network to continue to increase by circa 80% from now until the end of RIIO-3. The chart shown below utilises data from the FES falling short scenario and outlines the expected growth in wind generation capacity over the RIIO-3 period and beyond. The predicted 12% year on year increase will likely lead to a greater level of year-on-year volatility in the level of gas demand for power generation.

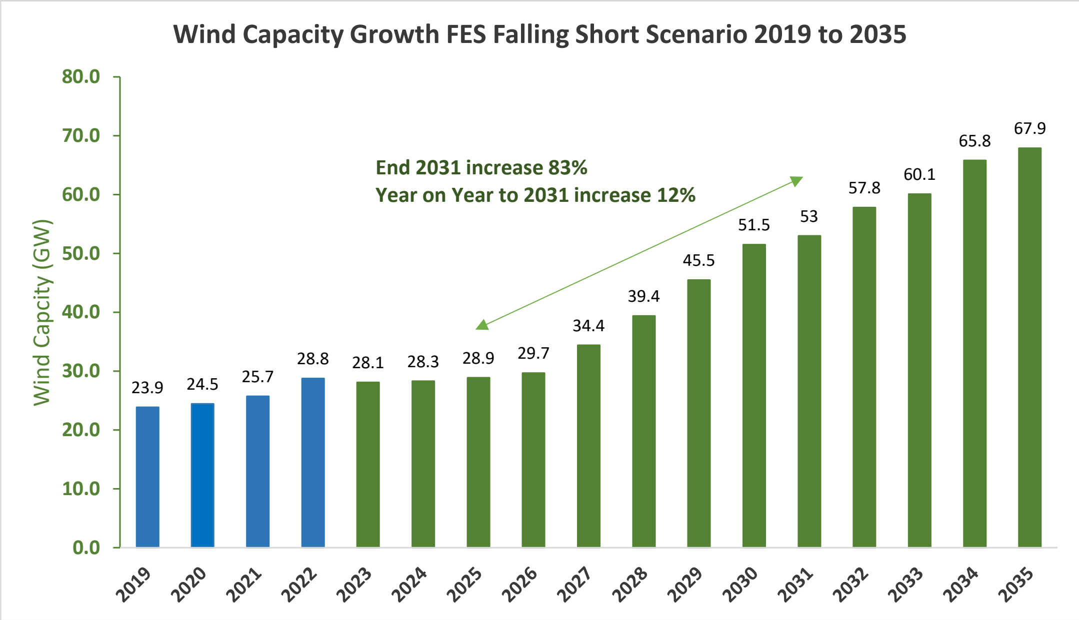

Figure 9

GTQ24. What are your views on the options presented for the D-2 to D-5 Quality of Demand Forecasting incentive?

99. As a result of the inputs being more uncertain than under D-1 scheme due to the time lag to the gas day, we support the continuation of a reputational scheme for D2 to D5 over the reintroduction of a financial scheme.

100. Reputational incentives encourage transparency in reporting and enhance focus on performance. However, they carry limitations in terms of the level of investment (in models, tools, or resources) companies make to outperform the targets.

101. As with the D-1 scheme we believe that scheme parameters should be reviewed and recalibrated to reflect the changing market dynamics seen in recent years, as well as to take account of future volatility.

102. Whilst there have been market developments, such as D-5 DSR, which places a greater reliance on the D-5 forecast, we continue to believe that a reputational incentive remains appropriate.

103. We consider that reputational incentives encourage transparency in reporting and enhance focus on performance and therefore in some circumstances can have benefits to the market. However, they do carry limitations in terms of the level of investment (in models, tools, or resources) companies may make to outperform the targets.

104. During the first two years of RIIO-2 our performance has been broadly aligned with the D2 to D5 target. However, as a result of the inputs being more uncertain due to the time lag to the gas day, we support the continuation of a reputational scheme for D2 to D5 over the reintroduction of a financial scheme as the level of confidence in the accuracy of input data and, as such, the models, reduces the further ahead of the gas day we forecast and therefore D2 to D5 improvements are not guaranteed. We do recognise that these forecasts are an important aspect of the DSR suite of products and will continue putting efforts into ensuring that we are best equipped to support them. It's worth noting that some improvements implemented for D-1 have supported performance in the D2 to D5 scheme.

105. We also believe that the benchmark or target parameters for the D2 to D5 scheme should be reviewed and recalibrated. The same elements relating to uncertainty and volatility that apply to D-1 are also applicable to D2 to D5, however due to the greater time lag between forecast and delivery in this scheme, those uncertainties are greater. In setting an appropriate target for this scheme future elements of volatility should also be considered.

GTQ25. What improvements to the D-1 and D-2 to D-5 incentive could be considered?

106. We welcome customer feedback on suggested improvements and are planning stakeholder/customer engagement this year to test our ideas with them, ahead of the submission.

107. In operating under the demand forecasting schemes we continually strive to evolve, develop and improve our processes to improve our outputs from it for the benefit of the market. We welcome customer feedback on suggested improvements and are planning and enacting stakeholder and customer engagement as we progress through this year to test our thinking and gain their input into developing future incentive scheme proposals, ahead of the submission of our final business plan.

GTQ26. Does NGT's D-2 to D-5 forecasts of demand provide a service that is valued by consumers and network users? Please explain why

108. Initial feedback gathered via Ofgem's recent engagement calls with Shippers, Distribution Networks and other interested parties suggests that D-2 to D-5 demand forecast provides value to the industry, especially in the context of its significance in the DSR process. Whilst we therefore believe the longer-term forecast is valued by our customers, as we outlined in GTQ24, we believe that a reputational incentive is appropriate. However, we look forward to gathering further views on this in our upcoming engagement with the industry.

GTQ27. Should the Quality of Demand Forecasting incentive be widened to include other areas of demand forecasts? If yes, which ones?

109. We are open to customer feedback regarding widening the incentive to other areas of demand forecast, but each request will need to be assessed on individual basis and will need to ensure that the correct balance of risk and reward is achieved within any such extension to the scheme.

110. Whilst we are open to customer feedback regarding widening the incentive, we are not currently aware of any areas which our customers require. Should there be other areas of demand forecast requested, each will need to be assessed on individual basis. We will need to ensure that any suggested changes benefit more than one party and that the correct balance of risk and reward is achieved within any such extension to the scheme.

111. The consultation contemplates the potential for a regional element to the scheme. At this time, we are not aware of a request from our customers for this, but we will seek to understand any such requirements through engagement as we develop our business plan. Our initial view, however, is that a regional scheme has limited value from an NTS perspective as both ourselves, via our Residual Balancing role, and the shippers, balance to a national level and therefore our view is that it makes sense for the Demand forecasts to align at the national level. Furthermore, it is worth noting that localised demand forecast is already produced by the Distribution Networks and published on our data portal[16] daily.

GTQ28. Do you agree with our minded-to position to retain all three elements of the maintenance incentive as a financial incentive in RIIO-GT3?

112. We agree with the proposal of retaining all three elements of the incentive.

[16] Find gas data | National Gas Transmission Data Portal

113. In the recent engagements our customers highlighted that NGT should have an upside opportunity to continue to incentivise working closely with customers to minimise impacts.

114. Customer impacting maintenance work is likely to intensify in RIIO-3 therefore the window of maintenance alignment opportunity will shrink. This means the efforts to align maintenance and not changing maintenance plans will become more challenging.

115. Considering the added challenge RIIO-3 will bring to deliver the right outcomes for our customers in this incentive, we think there is a scope to consider symmetrical parameters around all three elements of the incentive.

116. The initial customer feedback gathered via Ofgem and direct engagement indicated that our customers value the Maintenance incentive and that they think it should be retained in RIIO-3. Furthermore, some customers stated that there should be a financial reward assigned to this incentive as it steers the right behaviour and encourages NGT to aligning maintenance work with customers minimising its impact on the market. We agree with our customers that all three elements of the incentive should be retained with symmetrical parameters

117. In our view the incentive influences our behaviour and ensures, as far as reasonably practicable, that we undertake maintenance activities at the most opportune time for our direct connected customers to minimise any downtime of their plant and therefore the financial impact maintenance activities would have on them. Under the connection contract agreements and UNC, we are entitled to issue a certain number of Maintenance Notices to our customers to effectively force them offline when maintenance is undertaken. The incentive ensures that we don't use Maintenance days by default i.e., that we only utilise this right where a mutually beneficial time to undertake the maintenance cannot be found.

118. Despite the maintenance work increasing, as stated in the Ofgem's SSMC consultation, we have managed to perform well under the maintenance targets. This will become more challenging in the future. As shown on the chart below, in the last 3 years (2021-2023) we have seen a strong correlation between our Capex spend and the number of notices (both maintenance and advice) sent to our customers.

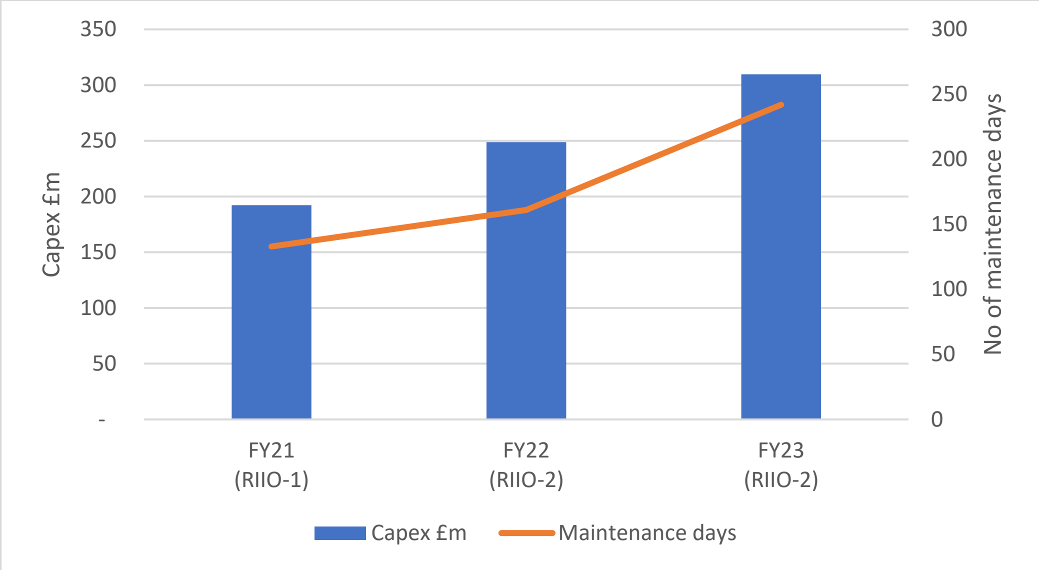

Figure 10

119. With Capex spend likely to increase in RIIO-3 (it is expected that this trend will continue), an increase in customer impacting work is likely. We will, therefore, be more likely to have a narrower window of opportunity to align our work with our customers and will need to put more effort into planning. Therefore, we think we should continue to be incentivised, including being financially rewarded or penalised, on all three elements of the maintenance incentive. The incentive targets will need to be recalibrated to capture the increase in risk related to growing maintenance activity, efforts required to achieve the outcomes desired, as well as consider our recent performance.

GTQ29. Should the Maintenance incentive include any other types of maintenance work that are currently not included in the incentive? If yes, please explain which one

120. At this stage we don't think any additional works should be added to the incentive scope.

GTQ30. Do you agree with our minded-to option (option 1) for the CCM incentive? Please provide reasons for your position.

121. We agree with Ofgem's preferred option 1 to review incentive parameters, but we don't think major changes are needed.

122. We believe that the structure of the incentive works well in principle. Our baselines are set to reflect the maximum theoretical physical capability under peak condition, and as such, cannot necessarily be met 365 days of the year. This means that there is a risk we may oversell capacity beyond expected levels of network capability. The incentive supports management of that inherent risk on behalf of our customers and stakeholders.

123. The incentive influences our behaviour; it stimulates proactive review of our risk management strategy to ensure we respond appropriately to changing market dynamics. Furthermore, it encourages us to take on risk and have suitable contingency plans and measures in place to ensure constraints are managed in the most cost effective and efficient way.

124. The incentive parameters should be recalibrated to ensure that they are reflective of operational realities, fit for purpose according to changing market conditions, and account for future costs and risks. The review should also account for the risks we have proactively managed to mitigate constraint risk and the constraints which materialised. However, past constraints and behaviours should not be solely considered as a projection of what might happen in the RIIO-3 period. The level of risk will depend on the planned investment in our assets' health and related maintenance activities. We expect more risk may materialise during RIIO-3 as a result of changing supply patterns such as increasing LNG volumes to the UK and decline in UKCS production.

125. How that risk and reward then should be split between NGT and the industry / customers / consumers should be carefully considered.

126. We believe that the parameters of the incentive need to be recalibrated to reflect the anticipated RIIO-GT3 market dynamics (i.e. risk of future constraints and related costs), but fundamentally we don't think the structure of the incentive or the calculation of costs and revenues should change in principle at this stage.

127. We recognise that this is a complex area to understand, therefore we think it is worth reiterating the basis of the regime which the current incentive has been designed around. We recognise that constraints are typically low likelihood high impact events and there is inherent risk (a "top down" regime), risk of unplanned events, global events impacting market dynamics and planned maintenance that we manage.

Inherent risk

128. The inherent risk is driven by structure of the regime which dictates the level of capacity we are required to sell (Baseline). Our baselines are set to reflect the maximum theoretical physical capability of a network point under peak conditions, and as such cannot be met 365 days of the year. Some more recent baselines have been driven by the investment signals received from Shippers and Ofgem's position relating to the investments and associated risks. This structure means that there is a risk we may oversell capacity beyond expected levels of network capability on any given day. The incentive supports management of that inherent risk on behalf of our customers and stakeholders. For example, in the summer our capability is lower across the network as demands are lower, but we are obliged to make the baseline capacity available and if this is purchased/flowed against at an Entry Point, we would be unlikely to be able to safely accommodate this level of flow at that Entry Point. This inherent risk has increased over the years as the supply to the UK market has become more flexible and more closely linked to global drivers and as such, global events have a greater impact. For example, LNG markets diverted

flows to the UK as the impacts of the Russia / Ukraine war on energy were understood and when Asian demand has fallen etc.

Unplanned events.

129. As our plant and equipment becomes older unplanned events related to asset health become more likely. The level of resilience at sites then becomes critical and maintaining asset availability may become more difficult i.e. faults may take longer to fix to maintain operability, which in turn may have the effect of increasing the constraint risk.

Planned maintenance.

130. Similarly, as the plant and equipment ages, it may require longer interventions to ensure that it remains available for use / compliant with the latest rules and regulations (whether emissions, IT etc).

131. The incentive and the exposure to risk/reward influences our behaviour; it stimulates a proactive review of our risk management strategy to ensure we respond appropriately to changing market dynamics. Furthermore, it encourages us to take on risk and have suitable contingency plans and measures in place to ensure constraints are managed in the most cost effective and efficient way. For example, in RIIO 2:

- We released non obligated exit capacity at Bacton Exit to support our customers' requirements to flow gas to Europe during summer 2022 and winter 2022/23 which created additional risk which we proactively managed.

- We highlighted the increased risk at Milford Haven in both the summer of 2022 and 2023 through Entry Capacity Methodology Release (ECR) consultations[17] and although there were a range of views amongst our stakeholders and customers on the solutions, highlighting the potential risks to customers and stakeholders was in our view key.

132. It is worth noting that although constraints may not manifest, we are proactively managing the network and incurring costs which the incentive encourages us to do. Such proactive management can involve moving maintenance (as we did for both examples detailed above), having specific contracts pertaining to specific site equipment, assessing risk and having operations staff on site etc. As part of this assessment, if requested, we assess the risk of releasing additional non obligated capacity.

133. We believe that the incentive parameters should be recalibrated to ensure that they are reflective of operational realities, fit for purpose based on changing market dynamics, account for future costs and risks and balance the risk between NGT and customers/consumers. The review should also account for the risks we proactively manage to mitigate constraint risk and the constraints which

[17] https://www.nationalgas.com/capacity/capacity-methodology-statements

materialised. However, past constraints and behaviours should not be solely considered as a projection of what might happen in the RIIO-GT3 period. The level of risk will depend on the planned investment in our assets' health and related maintenance activities. We expect more risk may materialise during RIIO-3 as a result of changing supply patterns such as increasing LNG volumes to the UK and decline in UKCS production.

134. We would also like to expand on the performance of this scheme in 2021/22 and 2022/23. In 2021/22 the scheme capped out (£5.2m) due to constraints on the network and us taking Locational Sell to resolve an Entry constraint (a revenue to the scheme) which were the most efficient actions. In 2022/23 we did not cap out, but were within 90% of the cap. This was due to us supporting flows (whilst assessing the risk each day) to Europe by releasing non obligated Exit capacity. For every £1m of non-obligated capacity sold we received circa £50k within the scheme. We think that the reward related to the release of non-obligated capacity should be reviewed to ensure that the added risk related to its release, greater costs as well as increased customer benefits are captured in RIIO-GT3 scheme parameters.

135. We believe that the structure of the commercial regime and the incentive scheme provides a strong incentive on NGT to meet customer requirements to allow them to deliver gas onto and take gas off the network when and where they want. Furthermore, we believe that the same principle should be applicable to both entry and exit elements of the scheme.

136. It is our view that the cap of £5.2m is relatively small in the context of the value the incentive brings to GB gas market, and the impact constraints and the lack of access to flow gas would have on NBP (and potentially wider market) in its absence.

GTQ31. Do you have any views on introducing seasonal baselines into NGT's licence at the start of the RIIO-GT3 price control?

137. We are assuming that this relates to entry baselines only and have answered on this basis. The industry feedback on introduction of seasonal baselines gathered as a part of the Entry Capacity Release Methodology review process in 2022 was negative. The dominant views expressed were that capacity baselines are associated with financial investment decisions and that any changes to it may weaken the confidence in the regime and the UK as a market.

138. Introduction of seasonal baselines would mean that several consequential regime changes would need to take place i.e., rules related to substitution, user commitment, NPV test would need to be revised to name a few. If a major shift in the regime is to happen, which introduction of seasonal baseline would create, we think it would be more appropriate if it was considered once there is more clarity regarding the future shape and the purpose of NTS (i.e. once the decision re introduction of hydrogen blending, and re-purposing for 100% hydrogen network / CCS, are made). Should the policy decisions be to enable hydrogen into the

network, operational and commercial framework changes will be required. We think it is going to be more appropriate to consider seasonal baselines at that time. This would then tie with considering other fundamental commercial changes that may be required. We believe that it is more appropriate to consider seasonal baselines at that time rather than under RIIO-3.

139. Although the environment has changed it may be worth reflecting on why “top down” baselines were introduced. The original capacity made available under the Revised Gas Trading Arrangements (introduced in circa 1999) were based on seasonal normal baselines. This generated a perception of scarcity in the market and drove up prices hence the approach was amended to a “top down” regime with a Constraint Management incentive.

140. Although we are not supporting an introduction of seasonal baseline at this stage, we will consult on a RIIO-3 proposal regarding changes to our current baseline in the coming weeks.

GTQ32. Do you agree with our minded-to position to retain the Residual Balancing Incentive in its current format? Is there merit in considering a recalibration? Please provide reasons for your position.

141. We agree that the scheme should be retained in its current format. .The scheme incentivises us to manage our residual balancing in the most efficient way and minimise our impact on the market. Furthermore, it also helps the market to respond to events/information and as such we believe the scheme aligns with customers’ requirements.

142. The scheme also creates a natural tension between the two elements of the scheme: Linepack Performance Measure and Price Performance Measure.

143. Scheme parameters need to be recalibrated to reflect the changing market dynamics seen since the start of RIIO-2, the roles we undertake and the scale/value of our residual balancing activity within the market.

144. The recalibration should also include consideration for a more symmetrical scheme and to reflect the significant value the efficacy of our residual balancing actions creates for our customers and end consumers.

145. Given the increase in the scale of value of the incentive and market dynamics, the cap and collar need to be reconsidered.

146. In the following paragraphs we detail why we believe that the scheme parameters should be reviewed.

147. The table below shows how the closing linepack changes (average PCLP day to day volatility) from one day to the next as an average value for each formula year from 2019/20 (RIIO-1). The data shows that the day to day closing linepack change has increased from RIIO-1 to RIIO-2, indicating balancing has become more

challenging (which correlates with incentive performance). In addition, the number of days we have needed to take residual balancing actions has increased.

Formula year	Average PCLP day to day volatility (mcm/d)	Number of days traded.	% of days traded	Avg SAP (p/KWh)
2019	1.7	148	40%	1.00
2020	1.5	199	55%	1.07
2021	2.0	251	69%	5.40
2022	2.5	273	75%	6.34
2023 (to December 31st)	1.8	184	67%	3.05

148. Due to the average SAP price for the current formula year being circa 3 times higher than the average SAP price in 2019/20, and the price movement within day being greater than previously seen, which has presented a challenge. Alongside this we have also seen an increase in the number of days that we have entered the market in 2022/23 increased from 40% in 2019/20 to 67% in the current formula year (2023/24 to December 31st, 2023).

149. The increase in both price and our activity in the market is also reflected in the absolute value of residual balancing trades that we have taken i.e., in 2019/20 this was £57.6m, increasing to £67.9m in 2020/21, £398.1m in 2021/22 and peaking at £451.2m in 2022/23. We recognise that this will likely fall in 2023/24, but year to date (end of December 2023) this is currently £142.7m and 67% of days. It is also worth noting that based on the current cap/collar the scheme represents circa 0.009% of the overall energy value traded in the market.

150. Therefore, we believe that there is merit in the Price (PPM) target and caps/collars (including the daily caps/collars and the balance between the two) being subject to review to reflect the changing market dynamics experienced during RIIO-2 and our role/value within the market. Within this backdrop other elements / parameters of the scheme have been challenging (linepack) so far in RIIO-2, but we believe that they remain appropriate, although we are happy to discuss / review these and aim to engage customers for their views.

GTQ33. Do you agree with our proposed approach to cost categorisation?

151. We agree with the four main cost categories used at RIIO-GT2: load related expenditure, non-load related expenditure, operational expenditure, and non-operational expenditure.

152. Ofgem proposes to work with us to ensure there is sufficient granularity in the underlying cost categories, to improve cost assessment capability. We agree that

this is an area worth exploring in order to support transparency and robustness of cost assessment. However, there should be a clear expected benefit from any move towards further cost category granularity. There is a time and resource burden for both NGT and Ofgem associated with increased reporting requirements and additional review and assessment of more detailed cost data. Greater levels of granularity may also be challenging to deliver in the short term because our reporting systems were sized and developed to deliver RIIO-1 reporting requirements. Any requirement for further granularity beyond the RIIO-GT2 requirements should therefore be clearly justified and the expected benefit should outweigh the additional complexity and resource burden.

153. Furthermore, to ensure this review of cost categories is balanced, there should also be consideration of whether certain cost categories can be combined or simplified in order to reduce the resource burden for NGT and Ofgem. In our view cost categories should be informed by - or closely linked to - the outputs that the cost contributes towards delivering. It may be that a review of cost categories with this principle in mind can help improve the transparency and simplicity of our cost reporting.

154. In summary, we do not see any need for change to the high-level cost categories used at RIIO-GT2, and we are very happy to work with Ofgem to review the underlying granular cost categories to identify areas where more or less detail may be needed.

GTQ34. What are your views on setting allowances for internal costs and SO rewards and penalties from the ODIs?

155. We are keen to understand further and with more clarity what Ofgem are trying to establish with this question. We are also supportive of innovation that makes the cost assessment more transparent with a view to removing complexity.

GTQ35. Do you support the need for greater granularity and transparency in cost reporting and to better understand the relationship between GTO and GSO costs to further develop our cost assessment capability?

156. We acknowledge Ofgem’s desire for greater clarity around the split of costs between the GTO and GSO. Ahead of making any changes, we believe that it is important to have defined the principles of cost reporting and that appropriate cost allocation rules be considered against that.

157. With respect to greater granularity and transparency of cost categories more generally, please see our response to GTQ33 above.

GTQ36. Is the proposed toolkit appropriate or are there other assessment techniques that we should consider for RIIO-GT3?

158. We agree with Ofgem's proposal to use a cost assessment toolkit similar to that used at RIIO-GT2. It is important, when applying this toolkit, that:

a. The cost assessment method selected for each cost category is appropriate to the nature of the cost, the data available, and whether there is reliable information on comparator companies (given there are no direct comparators in our sector);
b. Where used, the cost drivers selected are appropriate; and
c. Suitable weight is placed on broader cost justification evidence, such as procurement information, given the limitations of certain cost assessment techniques in a sector of one.

159. With respect to the selection of cost assessment methods, we agree with Ofgem's proposals around the use of unit cost analysis (i.e. that it may be appropriate to consider multiple cost drivers, and that models should be cross-checked against historical data and expert view if necessary), and historical trend analysis (i.e. this should only be used when historical costs are a good indicator of future trends, and any volumes assessed together should be comparable). We would add that caution should be exercised when applying these techniques in a sector of one, because the small sample size makes it more difficult to identify data anomalies (for example due to specific one-off circumstances) and have a high degree of confidence over results. Close engagement is therefore required between us and Ofgem to ensure that all relevant considerations have been taken into account when applying these cost assessment techniques.

160. This also applies to the use of expert review and project assessment. Given that these techniques require some degree of subjectivity, an open dialogue is required to ensure that Ofgem and its expert advisors have all of the necessary information to make robust judgements.

161. Finally, we support the use of benchmarks where appropriate. However, given that we are a sector of one, the use of benchmarking needs to be applied with caution. Data from other sectors can provide valuable insight, but it is important to ensure that the activities being carried out in those sectors are genuinely comparable to our activities. When benchmarks are being used, they need to be transparent and we must be able to scrutinise the benchmarking information to ensure comparability.

162. For example, Ofgem states that business support costs are common across both gas transmission and gas distribution, enabling cross-sectoral benchmarking. However, before such benchmarking is carried out, it is important to consider whether the data is fully comparable (e.g. do the costs capture the same detailed set of activities), and whether the nature of the activities is comparable (e.g. is NGT's business support function different in any way to that of the gas distribution companies, for example due to different back-office requirements for supporting more complex projects). There are clearly limits on the extent to which NGT itself can explore these questions and therefore we would like to work with Ofgem to obtain robust understanding of the data which should ultimately result in more robust models. If there are limitations in the comparability of data, then

benchmarking can still be carried out, but the weight placed on it should be more limited (e.g. a lower catch-up efficiency benchmark can be set).

163. We are carrying out our own internal benchmarking activity on the business support functions – this will enable us to assess the fitness of the proposed Opex and OMGS. Together with this, we have implemented a rigorous assurance process which ensures each investment proposal is fully justified. Also, following review of how Opex and CAI costs were distributed, our analysis of the regression models used for RIIO-2 cost assessment is that there was insufficient data and difficulty in modelling the complexity of drivers that made it difficult to draw any meaningful conclusions from the models. We would therefore be wary of placing too much weight on similar models for RIIO-3.

164. Next, in relation to selecting cost drivers we would ask that there is close engagement between us and Ofgem on this. It may be useful to establish an agreed set of principles for cost driver selection, including:

   a. The cost driver(s) selected make engineering and economic sense in terms of explaining the level of cost, and the rationale for using the driver(s) is transparent;
   b. The cost driver(s) selected fully explain changes or differences in cost (i.e. there are no material omitted variables);
   c. The cost driver is exogenous (outside company control); and
   d. Cost driver data is readily available and reliable.

165. Finally, given that we do not have any direct comparators to enable robust benchmarking, it is important that Ofgem's cost assessment approach takes into account broader cost justification evidence. To aid in this, we propose to establish robust investment principles which are discussed and agreed with Ofgem. This will provide Ofgem with transparency on how we've derived our costs. We have established robust methodologies that outline what approach we have taken to calculate costs, and these methodologies can provide Ofgem with confidence that we have a process that can be reviewed to understand how costs have been arrived at.

166. In addition:
   a. We have created a Scope, Volume and Cost (SVC) standard for each cost area to score proposed investments against (see Figure 11). This ensures that each investment proposal receives the same level of scrutiny, and we are able to assess which carry more risk.
   b. For Unit Costs relating to asset health activity, we have created a process which we see as being the most robust and accurate reflection of cost for the activities we carry out. Should we lack evidence of out turn or forecasts estimated cost of completion data, and we are unable to competitively tender the work activity, we will use the 1st principle estimating process. We have collated large quantities of data relating to labour rates, machine costs which we can also regionalise to enable us to create bottom up costs assessment, piecing together the elements of the desired activity.

c. To ensure that we have comfort that the process we have designed, we have engaged expert consultants to come in and ‘benchmark’ the process. They will assess all the elements of what we’re proposing and measure it against other techniques they have seen in operation before. The scope also includes following the process through from a previous work activity and verifying the outturn cost as being accurate.
d. Where possible, we have sought expert support to carry out detailed benchmarks to evidence that our costs are both accurate and efficient. With regards to our IT investments, we have engaged expert consultants to ensure that the costs that are being proposed have been through extensive review by an expert reviewer (Gartner), these are industry leading and provide a high level of comfort that our costs are within an acceptable envelope, if they’re not, they do not make it into the submission.

167. Our SVC framework ultimately reflects the ‘stages’ of assessment which we believe Ofgem will need to follow in assessing the efficiency of our business plan submission in respect of asset expenditure.

a. It is clear that the first step will be for Ofgem to get comfortable that the scope of work we propose and the volume of work are all necessary and to the benefit of customers. A fundamental driver here will be the need for us to deliver ongoing resilience of the transmission system (see further discussion of the progress for developing a resilience standard in OVQ41). We will provide Ofgem with full transparency over the scope and volume of work proposed in our plan and the associated needs case driven by benefits to consumers.
b. Once Ofgem is comfortable that the scope / volume of works is in the customer interests, it must then assess whether the costs to deliver that scope/work are efficient. This is primarily where use of the toolkit comes in.

168. Our overall view is that by using the combination of the established cost assessment toolkit (subject to development to improve robustness) alongside open and transparent engagement using our SVC framework should give Ofgem very high confidence that the resulting overall ‘baseline’ totex allowances are thoroughly well justified and robust. Uncertainty over any elements of spend can be handled by appropriate uncertainty mechanisms and/or PCDs / ODIs. We therefore strongly expect that Ofgem can and should be able to apply a cost assessment framework which results in robust allowances, despite the challenges associated with being a relatively unique sector. A transparent and robust cost assessment process is an essential underpinning for the price control and also enables us and Ofgem to have confidence in the parameters which might result from Ofgem’s BPI assessment (including any reward/penalty associated with Ofgem’s assessment of our plan; and any consequential impact on the sharing factor). We think this is critical in order to avoid the arbitrary outcomes of the RIIO-2 BPI which unfairly penalised us and resulted in weaker incentives.

Investment Proposal Principles

NGT propose to establish robust investment proposal principles to create a comparator to which the GDNs have at their disposal. This provides Ofgem with transparency on how we've derived our costs. Delivers a robust methodology to calculate costs that can provide Ofgem with confidence that we have a process that enables a transparent approach and review of how they have been derived our costs. For example, each investment will also comply with an internal Scope, Volume and Cost (SVC) standard which provides a level of confidence that is open to scrutiny and maintains a consistent approach to deriving costs.

This process can give certainty around the level of cost and provide the regulator and stakeholders with the assurance that we are operating to best in class approach that is auditable and transparent. This approach will lead to high cost confidence and if embedded into the regulatory framework, would address the issues we face as a sector of one.

Figure 11

GTQ37. Do you have any views on the UMs needed for RIIO-GT3?

169. There will be the need to carry over some (not all) of the RIIO-GT2 re-openers. Resulting from lessons we have learned over the RIIO-GT2 price control period so far, there will be areas where we will be proposing to established new RIIO-GT3 re-openers.

170. Specifically, we see the need to establish a resilience re-opener (see response to OVQ41). We have also provided our views on a re-opener to manage the impact of introduction of the CSNP and gas strategic planning processes as part of response to GTQ1 and GTQ2. There are currently other areas we might propose new re-openers, these will become clearer as our business plan develops and we will be considering proposals that would remove regulatory burden for both Ofgem and Gas Transmission, which could be to retain the mechanism or set allowances if there is suitable cost and scope certainty.

171. For any of the retained or new re-openers the timing and trigger mechanism will also need to be explored and agreed.

172. We have provided a summary below detailing our view on RIIO-GT2 re-openers and pass-through uncertainty mechanism.

Output name	Ofgem initial review outcome	NGT SSMC view
Compressor emissions Re-Opener	Review whether still need for reopener mechanism in GT3	See response to GTQ11.
Funded incremental obligated capacity Re-Opener and PCD	We consider that a reopener will still be needed in GT3. We are minded to retain this re-opener as we believe it ensures good value for consumers. We still see a need to manage the potential costs associated with the release of incremental capacity.	We agree with Ofgem's position and would see this re-opener to be carried forward into RIIO-GT3.
Net zero Re-opener and PCD	We consider that a reopener will still be needed in GT3	See response OVQ4, OVQ35, OVQ38.
Net Zero Pre-construction Work and Small Net zero Projects Re-opener	Review reopener functioning as intended and what it would be used for in the next period	See response OVQ4, OVQ36, OVQ37.
Coordinated adjustment mechanism (CAM) Re-opener	Review function and scope of this reopener	See response OVQ39.
Asset health Re-opener	Funding for asset health not covered by NARM is likely to be needed in the next price control. The rationale for this re-opener needs to be reviewed in parallel with setting NARM funding.	We agree, there might be the need for a specific Asset Health re-opener.
Physical Security Re-opener	Review use of reopener and overall	See response to OVQ40.
Bacton terminal site Re-opener	Remove as no longer need for Re-opener	See response to GTQ15.

King's Lynn subsidence Re-opener	Remove – no longer need for Re-opener	See response to GTQ16.
Cyber Resilience IT PCD and Re-opener	Review PCD requirements and functionality of reopener (reopener windows, trigger)	See response to OVQ46.
Cyber Resilience OT UIOLI, PCD and Re-opener	Review UIOLI funding approach, functionality of reopener (reopener windows, trigger) and PCD requirements	See response to OVQ46.
Quarry and Loss Re-opener	Remove – likely to no longer be a need for a reopener. We don't believe this re-opener is necessary in the next price control as the uncertainty has been dealt with in RIIO-2.	We believe there is still a need for this re-opener as the uncertainty around this area of spend remains in RIIO-T3. Our business plan will include Baseline and re-opener values for this area.
Pipeline diversions Re-opener	We see there being rationale for the retention of this re-opener as we believe it ensures good value for consumers. We will work with NGT and stakeholders to review whether the re-opener has been used as expected during GT2 and see if there are any improvements that can be made.	We agree with Ofgem that there is a need to retain this re-opener. There is also a need to widen this re-opener to other diversions which are required but we are unable to forecast – eg landslides, collapse of pseudo-tunnels, farming changes, buildings erected above pipelines and similar. We welcome further engagement with Ofgem on this.
Policing costs Pass-through	We intend to continue to treat these costs as pass-through.	We agree with Ofgem's position.
PARCA Termination Value Pass-through	We intend to continue to treat these costs as pass-through	We agree with Ofgem's position.
Hynet FEED Study Pass-through	The Hynet design study will be completed by Cadent in RIIO-2, therefore we propose to remove this mechanism for RIIO-3.	We agree with Ofgem's position.
Adjustment to the Net Zero Pre-construction Work and Small Projects re-opener Pass-through	We intend to continue to treat these costs as pass-through.	Net Zero Pre-construction Work and Small Projects is a re-opener and not 'pass-through' for NGT.
Gas Conveyed to Independent Systems Pass-through	We intend to continue to treat these costs as pass-through.	We agree with Ofgem's position.
Non-operational IT Capex Re-opener	N/A	See response to OVQ38b.

GTQ38. Do you have any views on current reporting requirements and structure at the cost category level and how this may be adapted to better suit RIIO-GT3 and related development of BPDTs?

173. The RIIO-GT3 BPDTs and associated guidance underpin the production of a clear and consistent view of our data submissions, support policy development and cost assessment and provide the basis against which to report delivery in RIIO-GT3.

Timing

174. The BPDT require timely development to ensure licensees have sufficient time to collect and populate the data in the required format before then carrying out governance processes. With draft submissions of the BPDT required in July 2024 and GT already well progressed in developing its business plan, early sight of the BPDT is required. We appreciate that draft tables will be shared prior to their publication but highlight that final publication in spring may result in limited time to populate and perform governance processes on the populated tables.

Structure and content

175. We support basing the format and content of the BPDT on the RIIO-GT2 Regulatory Reporting Packs (RRPs). This provides continuity of approach from GT2 to GT3 and will also assist in reporting GT3 actuals against the GT3 framework.

176. Specific advantages of adopting this approach are:
- It provides an opportunity to embed a core principle of regulatory reporting consistency between Price Controls.
- Consistency of approach optimising comparability between price control periods.
- Ofgem and GT already have familiarity with the RRP structure and approach reducing regulatory burden.
- Simplified reporting in GT3 if the BPDT and RRP structures remain consistent.

177. We recognise that additional detail may be required for the business plan submission as compared with RRP reporting. This should be limited to areas where the additional detail adds clear value to the business plan process. For example, where Ofgem demonstrate that additional granularity is required for cost assessment.

178. We also recognise Ofgem will require consistency of BPDT structure to allow comparison across networks. However, BPDT tables also need to be able to reflect circumstances specific to GT.

179. The GT business has and will continue to experience significant change over the RIIO-T2 and RIIO-T3 price control periods as we continue to optimise to the needs of our customers. The BPDT structure needs to be able to reflect these changes.

180. During RIIO-GT2 NGT's ownership changed with National Grid selling a majority shareholding. This results in 3 distinct reporting and forecasting phases across RIIO-T3 and RIIO-T2 (which is used for historic trend purposes):

- **Pre separation**: costs incurred by National Grid and allocated across regulatory entities according to the Unified Cost Allocation Methodology.
- **Transitional or long-term service agreement (TSA and LTA):** these are costs incurred post-separation with National Grid continuing to provide and charge for services.
- **Post separation:** NGT incurs costs based on a stand-alone business structure.

181. These phases are applicable to costs which were previously incurred across the National Grid Group and were allocated across regulatory entities i.e. business support costs.

182. The granularity of information available across each of these periods will differ and will, for pre separation and TSA periods, be limited. NGT will provide all information as far as we are able. However, data availability and granularity should be acknowledged and factored in to BPDT development and completion.

183. We have also discussed another structural and reporting change with Ofgem regarding the taxonomy of the asset health spend and which we consider should be reflected in the RIIO-GT3 tables. The change in taxonomy will apply from the start of the RIIO-GT3 period and whilst some high-level cost comparison to RIIO-GT2 will be possible, it will not be possible to recut data from price control periods prior to RIIO-GT3 in a similar manner.

184. The change in asset taxonomy offers many advantages to NGT and Ofgem. Firstly, it establishes a more representative database, aligning assets with the level of work undertaken. This ensures planned interventions occur at the correct level, allowing for precise application of unit costs and benefit reporting. Secondly, the shift directly integrates with our asset database systems, improving digitalisation and futureproofing. The new taxonomy will simplify reporting and reconciliation, ensuring seamless alignment between business plans, regulatory reporting, and efficient close out.

185. We have already engaged with Ofgem to share our thinking in these areas and welcome the opportunity to continue working with Ofgem to develop BPDT format and content.

Process

186. The process and basis for BPDT submission requires further clarity. In particular, we refer Ofgem to our earlier responses to OVQ1, OVQ2, OVQ8 and OVQ9

discussing the parallel development of the Hydrogen Transport Business Model (HTBM), our concerns with the use of two energy scenarios in developing the GT3 business plan and our proposal to use Falling Short as our base scenario.

187. Within the RIIO-3 methodology development careful consideration needs to be given to how the RIIO framework and HTBM will interact.. Dependent on the specific interactions, it may be likely that the BPDT need to capture costs pertinent to the RIIO-GT3 business plan and therefore separately identify continued investment in the natural gas transmission network including associated resilience and readiness spend to accommodate changing technologies and repurposing investment.

188. The Overview document and GT Annex reference the use of FES23 Leading the Way planning scenario as the common energy scenario for RIIO-3 submissions and also the proposal for Gas networks to plan using a common conservative scenario (FES23 Falling Short) to recognise the importance of maintaining security of supply and energy resilience through the transition to Net Zero.

189. It is unclear whether Ofgem is proposing submission of two sets of data ☐, one for each planning scenario. We do not consider submission of two sets of BPDT to be feasible in terms of the time required to populate and apply internal governance processes. Also, submission requirements should be of equal regulatory burden across all networks to ensure a fair and equal process. We consider that submission of a single set of data tables is the only practical pathway for both the draft and final submissions given the significant time taken to populate and complete governance processes.

190. In our responses to OVQ8 and OVQ9, we request greater clarity on the expectations that Ofgem are placing on the use of Falling Short as an 'additional common conservative scenario' in terms of the additional submission requirements that this place on gas networks, and on the relative weight that will be given to investment proposals that rely on one or other scenario. We outline our proposal to use Falling Short as our base scenario given we expect demands to remain sufficiently high during T3 in all scenarios to preclude any network decommissioning.

191. In the RIIO-GT2 submission, Ofgem requested data from the previous price control period to use as a comparison and to inform cost assessment and regression analysis. We assume that this practice will form part of the RIIO-GT3 submission. We support submission of historic data but note that the ability to provide this in comparable detail and format to that required for RIIO-GT3 data will depend on high consistency between RIIO-GT2 business plan submission and RIIO-GT2 reporting formats. Historic data prior to the RIIO-GT2 period was requested and reported using different regulatory cost categories and under different business plan guidance and therefore is not directly comparable to RIIO-GT2 and RIIO-GT3 information. Data prior to RIIO-GT2 will therefore have less relevance and could even mislead trend analysis.

192. We are keen to work with Ofgem to develop BPDT that provide sufficient information on which the business plans can be assessed but which does not create regulatory burden (for the networks or the regulator) which outweighs the benefit of providing the data.

NGT Response: Finance Annex

Finance overview

A balanced financial framework results in current and future consumers being fairly charged for the network they use and the services they receive. Careful assessment and calibration of the framework enables a balance to be struck between consumers benefitting from sustainably low bills and incentivising continued investment which retains flexibility in the network to meet future stakeholder requirements. This balance has always been important but is even more so during the current period of energy transition to Net Zero, ensuring that it delivers the most value to consumers whilst attracting necessary investment at a time when there are significant demands for such investment across multiple sectors.

Customer and stakeholders set out their expectations for networks and the services they want through constructive engagement. The financial framework needs to support the investment and behaviours required to drive these outcomes by allowing a return commensurate with the risks borne by networks which gives sufficient financial capacity and incentive to deliver the innovation and efficiencies to drive service improvement and reduce costs for consumers in the current and future price control periods.

The financial framework must be justifiable and determined using robust processes and assumptions. Assuming the inputs are appropriately assessed, NGT supports Ofgem's approach of broadly rolling forward the principles of RIIO-2 for the next price control RIIO-3, which includes the estimation of cost of capital by continuing to use the Capital Asset Pricing Model (CAPM) as the primary tool. This is in line with the recent UKRN (UK Regulators Network) Guidance Report, published on 23 March 2023, which recommended regulators should continue to use the CAPM as their primary approach for estimating their cost of equity and the CAPM remains in use by a wide cross-section of financial practitioners.

However, NGT strongly believes that the new pricing control needs to reflect changes in two key areas.

First, the risks gas transmission and other networks will face in future and to ensure those risks are truly reflected in the outcome from CAPM. This will require Ofgem to consider new evidence in respect of CAPM inputs or cross checks that assess whether CAPM really reflects these risks and to assess the principle of financeability more widely.

Second, Ofgem must reassess the available evidence on TMR. Yields on benchmark government bonds have increased by circa 3.5% since RIIO-2 was determined[18]. The RIIO-2 calibration reflected those low rates, the era of cheap money, which has ended

[18] Frontier Report – Equity Investability in RIIO-3 prepared for ENA paragraph 2 (a)

abruptly. All available evidence suggests the ultra low rates of the past are no longer relevant, and the RIIO-3 CAPM calibration needs to reflect this.

Evidence from cross checks indicates that the RIIO-2 calibration of CAPM adequately reflects neither of these key points. Not properly acknowledging growing risks and changed market conditions, and failing to ensure they are addressed in the calibration of the financing package, risks networks failing to retain and attract investment at a crucial time.

We conducted our review on Ofgem's Sector Specific Methodology Consultation (SSMC) Finance Annex and summarise the key points of our response below. Our focus here is on cost of equity, notional and actual financing structure, cost of debt allowances, inflation treatment policy options, asset lives and decommissioning. Our detailed responses to the Finance Questions then set out all our views on the framework and proposals for change in detail.

Our response is supported by reports commissioned directly or via the ENA, as summarised below. Specific references are provided throughout our response.

Prepared for National Gas

- Economic Insight – "Efficient Cost of Debt for Gas Transmission at RIIO-3" dated 4 March 2024

Prepared for the ENA

- Oxera – "RIIO-3 Cost of Equity" dated 23 February 2024
- Frontier Economics – "Equity Investability in RIIO-3" dated 5 March 2024
- Frontier Economics – "Initial Consideration of Break-even Inflation for Price Control Purposes" dated 5 March 2024
- Frontier Economics – "The Low Beta Puzzle" dated 5 March 2024
- NERA "Additional Cost of Borrowing for the RIIO-3 Price Control" dated 22 February 2024

Investability

The transition to Net Zero creates numerous challenges for the energy sector as a whole which will require networks to retain and attract significant investment. In NGT's case, key drivers of our investment plan such as the requirement to maintain a secure and resilient natural gas transmission network to the standards our stakeholders require, which includes maintaining an acceptable level of network risk and an uplift in the mandated levels of cyber and physical security standards, mean that the RIIO-3 plan requires more investment than in RIIO-2.

This increase in investment in the RIIO-3 period is consistent with our response to Ofgem's request for information in support of its Future Systems and Networks Regulation (FSNR) consultation in 2023. Whilst a financeability assessment was not carried out at that point, given the actions that were necessary to ensure RIIO-2 was financeable (change of depreciation methodology etc.), it could be inferred that without a change in financing parameters that such a plan would not be financeable at the required investment grade credit rating. Ofgem has an obligation to ensure networks remain financeable on reasonable terms in the face of these challenges and as such, we welcome Ofgem's proposals that the financeability assessment is to take into account wider investability.

NGT generally agrees with the outlined principles[19] of how Ofgem will review investability for RIIO-3. However, NGT recommends Ofgem expands its approach to assess wider indicators of investability, such as how the balance of risk and returns between networks and consumers are calibrated in incentive packages. NGT is also investigating whether the principle should be extended to how expected productivity gains are calibrated, again to ensure the appropriate balance of expected outcome and actions required to generate them is reached.

When assessing the principle of investability we have also considered Recommendation 7 of the UKRN Guidance, which stated that regulators should only deviate from the mid-point of the CAPM derived estimates if there are strong reasons for doing so. Whilst we note the UKRN guidance, we reiterate that the CAPM result should be assessed against the relevant principles to ensure that the result represents a return that is adequate to retain and attract investment in the sector and support the delivery of an ambitious business plan for NGT. This will require Ofgem to consider additional evidence to ensure forward-looking risks facing the sector are adequately reflected in the allowed return. As summarised in our detailed responses, Ofgem's process should therefore involve the assessment of new evidence presented in respect of a number of the CAPM data inputs (such as different beta comparators or data considered when assessing risk-free rate or total market return). Evidence presented by a range of cross checks, including those considered in previous price control periods where there is evidence that relevant factors have changed, infer that key inputs to CAPM need to react to evidence that risk is not currently adequately reflected in the proposed approach.

In respect of the cost of debt, Ofgem's proposed approach to debt financeability is similar to RIIO-2 and will therefore follow Recommendation 8 of the UKRN Guidance, which stated 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. The objective of this approach is to ensure that companies and their shareholders bear the risk of their capital structure and financing, not customers.

[19] RIIO-3 SSMC Finance Annex paragraph 5.10-5.16: [RIIO-3 Sector Specific Methodology Consultation – Finance Annex (ofgem.gov.uk)]

NGT generally supports this approach, however the specific proposals in respect of how inflation and index-linked debt are treated in the calculation of the cost of debt do not appear consistent with this principle and could potentially be damaging to NGT if not managed correctly, as expanded on later in this summary.

NGT also notes Ofgem's reference to other adjustments to the financing package, such as changing asset lives or capitalisation rates. Such adjustments have the effect of pulling forward cash from future periods and therefore whilst we understand that such adjustments to these parameters may be required for other purposes and they can have a favourable impact on financeability in the short-term, they can also cause long-term issues when used to address short-term financeability (for example, adjusting parameters such as asset lives or capitalisation rates can pull forward cash into near term price control periods, leaving longer-term price control periods exposed to lower and potentially unfinanceable levels of allowances). Adjustments to these parameters should not therefore be enacted to support a return deemed inadequate to attract investment.

Resilience

In SSMC, Ofgem recognises that it already has in place a suite of tools and reporting to enable monitoring the financial resilience of network companies. NGT takes its responsibilities in this regard seriously and has complied with these requirements during the RIIO-2 period. Ofgem itself states that these "have been broadly effective in helping shareholders and management to maintain financial policies and outcomes that are consistent with a financially resilient sector"[20]. This is consistent with the energy transmission and distribution sectors not facing the same issues as encountered in other sectors.

However, we do recognise that the energy sectors are facing evolving risks and there is a potential need to reassess resilience requirements given the experience of other sectors. Any changes proposed to resilience requirements and reporting need to reach a fair balance between appropriate insight and early warning of issues, whilst ensuring that restrictions do not unduly influence the choice of financing structures and flexibility that allows network firms to attract investment to the sector. An imbalance towards more restrictive requirements has the potential to undermine investability.

Subject to our response to the separate consultation on changes to annual reporting commencing from the FY24 period, some points of clarification on the interaction of resilience proposals and existing obligations in respect of ringfencing and assuming requirements continue to reference regulated entities only, NGT broadly supports Ofgem's current proposals of resilience requirements as they appear to reach that fair balance.

[20] RIIO-3 SSMC Finance Annex paragraph 6.8:
[RIIO-3 Sector Specific Methodology for the Gas Distribution, Gas Transmission and Electricity Transmission Sectors | Ofgem]

However, whilst NGT already holds two investment grade credit ratings, given the consequences of breaching the proposed requirement to do so, potentially due to reasons outside of NGT's control, we do not agree with including this as a requirement and support retaining the existing obligation that references networks making "reasonable endeavours" to do so.

Asset Lives

NGT supports the assertion in the SSMC that it is appropriate to address the asset stranding risk under the RIIO principles given the need to match economic lives to asset usage by the relevant population of consumers and the potential for negative investor perception of the sector if it is not managed. However, the RIIO framework and allowed WACC also needs to address related forward-looking risks such as the costs of decommissioning and uncertainties around the future of gas usage and the impact of new technologies.

NGT continues to support the assertion made in our RIIO-2 submissions that the starting point for setting asset lives should be the economic life of assets to align recovery of allowances with the value provided to consumers. The assessment should take into account changes in the technical/economic life and therefore adjusting asset lives is also recognised as an effective tool for addressing any stranding risk inherent in the move to new technologies. Any adjustment to asset lives to address stranding risk also needs to consider the balance of resulting consumer bill impacts being fair to categories of network users (i.e., natural gas, hydrogen and carbon capture, and storage (CCS)) as well as investors.

There are currently significant uncertainties in both gas usage scenarios and the extent of mitigation of the stranding risk presented by future business models such as hydrogen and CCS. We therefore believe that the best outcome at SSMD would be to leave a decision on asset lives open, allowing both NGT and Ofgem to continue to analyse and discuss the evidence available but also to focus on establishing a process that allows the transfer of assets to new business models.

Decommissioning

Ofgem notes in the SSMC that it does not expect significant decommissioning activity during the next price control period. NGT supports this assertion given the continuing need for a secure and resilient network over the RIIO-3 period and the decommissioning activity already carried out on certain redundant assets, such as non-compliant compressors, in RIIO-2. However, it is important to establish principles for decommissioning assets that may not be utilised in future energy mix. Not doing so may risk natural gas consumers being charged too much or too little for assets from which they have derived value. Furthermore, given the significant levels of potential gas network decommissioning costs included in the recent assessment by the National Infrastructure Commission, which has led to questions from rating agencies and debt finance providers, the longer such a risk goes unaddressed, the higher the potential for higher financing costs given the ongoing regulatory uncertainty for investors, which would ultimately lead to higher costs for the consumer.

Current obligations to decommission network assets are dictated by health and safety and environmental legislation rather than obligations within the Gas Transporter licence or wider regulation. There is, however, precedent for the costs of decommissioning assets no longer required being funded via RIIO allowances, as was the case in RIIO-2.

We note that business models and regulatory regimes for future businesses associated with the Net Zero transition (i.e., CCS) currently being established will include a requirement to decommission assets at the end of life, with financing packages/revenue models built accordingly. Introducing a requirement to decommission assets at the end of their useful life without a corresponding allowance mechanism would seem inconsistent with both those new business models and the precedent set during RIIO-2.

Establishing a methodology that facilitates the transfer of assets and their regulatory value to new businesses (i.e., hydrogen and/or CCS) allows Ofgem and NGT to protect natural gas customers from the costs of decommissioning assets that would otherwise be incurred should those assets not be repurposed, as well as partly mitigating the risk of stranding assets. There are uncertainties around the proportion of the network that will ultimately be repurposed and therefore in NGT's view RIIO-3 should focus on establishing a methodology and mechanisms for both asset transfers and decommissioning remaining assets in the future. In our detailed response we have set out two broad mechanisms that could facilitate the collection of decommissioning funding but, as with asset lives, it may be necessary to focus on establishing methodologies to facilitate a response to such matters within the RIIO framework but ultimately hold back on a definitive decision on asset lives and the amount of decommissioning required until the point at which there is more clarity on future business models and the subsequent impact on the natural gas RAV. This may be a re-opener mechanism during RIIO-3, which if restricted to specific parameters rather than a wholesale reassessment of the financing package may be a practical solution.

Indicative Allowed Return

Setting the right allowed return is critical in ensuring networks are able to fund future infrastructure and have adequate financial capacity to manage uncertainty around the energy transition. UKRN guidance states that regulators should estimate an allowance for an efficient company under the notional company structure for the relevant sector, with actual debt costs suitably benchmarked against other market evidence.
The cost of capital is reliant on setting a cost of debt and equity value appropriate for a notional, efficient company.

Cost of Debt

We support a methodology for the cost of debt allowance to be a fair and reasonable estimate of the actual cost of debt likely to be incurred by a notionally geared, efficient network company. However, there are certain specific considerations that we believe should be addressed.

In RIIO-2, the allowed cost of debt was constructed utilising data from an index of borrowing costs deemed to best align to the sector (IBoxx Utilities 10yr+) and an allowance for additional costs that are not fully reflected in that index output, adjusted to a real allowance using the long-term CPIH assumptions set in RIIO-2. There is strong evidence for an increase in risk for gas networks relative to electricity and to RIIO-2, which manifests as a higher cost of borrowing and lower tenures for the gas sector. As such, it is appropriate to assess NGT efficient costs against a comparator group of GT and GD, which provides an appropriate balance of reflecting the divergent risk between electricity and gas and maintaining a comparator that extends beyond NGT alone.

Following on from its Call for Input on the impact of higher inflation issued in August 2023, Ofgem has proposed in SSMC a series of alternative treatments for the use of inflation to adjust the cost of debt allowance from nominal to real, with the stated objective of removing the so called “leverage effect”. As we documented in our response to the Call for Input[21], NGT is not forecast to benefit from higher inflation across the RIIO-1 and RIIO-2 period, primarily because its proportion of inflation-linked debt is higher than the sector average and that assumed by the notional company financing structure in RIIO-2.

NGT does not support the proposal to remove the proportion of index-linked debt when setting the cost of debt for the notional company as it does not appear consistent with the principles set out in the UKRN Guidance or long-established regulatory principles. As expanded on later in this summary, in addition to not having benefitted from the leverage effect, NGT would face significant and costly practical issues if it were expected to follow the proposed notional position and transition to holding zero index-linked debt.

Cost of Equity

The UKRN guidance recommendations are considered to generally align with the principles of setting such allowances in RIIO-2, being centred on the use of the CAPM to estimate the cost of equity with broadly the same methodologies being applied to key inputs such as risk-free rate, equity risk premium and beta. NGT supports the use of CAPM to generate such a range but note again that the new price control needs to reflect changes in wider capital market conditions. Critically, it must also reflect the risks gas transmission will face in the future and to ensure those risks are truly reflected in the cost of equity granted. Networks are facing unprecedented and different challenges that may require Ofgem to consider current market data and potential wider comparatives than it has in previous price controls; this may lead to a need for data or comparators disregarded in previous price controls to be re-assessed.

[21] National Gas Transmission Response to Call for Input dated 26th September 2023: [Call for input - Impact of high inflation on the network price control operation | Ofgem]

Accordingly, Ofgem states that it is open to considering new evidence to consider whether the proposed approach adequately reflects the risks networks are facing in the future, risks that have evolved since during RIIO-2. A key challenge of this assessment is that the CAPM inherently relies on historical data and on suitable listed comparators to provide data on beta in particular. As such, Ofgem should consider evidence provided by data on additional listed companies or additional cross checks not considered in RIIO-2. The consideration of cross checks is consistent with UKRN Recommendation 7, that recommends the use of cross checks to sense check the overall cost of equity derived from the CAPM derived midpoint but that the midpoint should only be deviated from if there are strong reasons to do so. Ofgem agrees with that recommendation and proposes to adopt it in RIIO-3.

NGT supports the use of cross checks to sense check with the overall cost of equity and has therefore commissioned various studies into suitable cross-checks in collaboration with the ENA. Further detail is presented in our question responses and in reports appended to our response but these indicate that a higher cost of equity is required to adequately reflect the risks facing the sectors. Similarly, we present evidence from work performed by Oxera on behalf of the ENA that additional data should be considered when assessing the Risk-Free Rate and Total Market Return elements of the calculation of cost of equity to properly reflect the principles inherent in calculating such benchmarks and fairly reflecting the appropriate risks. In particular, there has been a clear correlation between interest and gilt rates and the levels of TMR allowances granted by regulators in past price controls, which would infer a higher TMR for RIIO-3 should the same principles be applied.

Treatment of Inflation Changes

Within the proposals for calculating cost of debt allowances, Ofgem makes proposals on how it intends to respond to responses received to its Call for Input on the matter of inflation, the focus of which is to remove the so-called “leverage effect”. This effect is observed when outturn inflation exceeds the inflation assumed when setting cost of debt allowances and is particularly prevalent in companies that hold a higher proportion of fixed rate debt.

NGT responded[22] to the inflation Call for Input and demonstrated that using Ofgem’s modelling principles and information available at the time, NGT is not forecast to benefit from the leverage effect across the RIIO-1 and RIIO-2 periods (£24m “loss” forecast at the time of responding). NGT’s financial structure is significantly different to the current notional financing structure assumptions; it maintains a relatively high proportion of inflation-linked debt which offsets the additional CPIH indexation. NGT’s financing structure both reflects investor preferences and the RIIO framework. NGT not benefitting from the effect Ofgem lays out could be seen as evidence that the risk associated with the period of inflation has been effectively addressed.

[22] National Gas Transmission Response to Call for Input dated 26th September 2023: [Call for input - Impact of high inflation on the network price control operation | Ofgem]

A significant change to a well-established methodology in order to address temporary concerns that emerged for a relatively short term period of high inflation would seem out of line with best regulatory practice, given how effective the existing approach has been in attracting substantial capital into energy networks at low cost.

Furthermore, to fully eliminate the leverage effect, Ofgem also proposes that two out of the three proposals are accompanied by a significant change to the notional company financing structure, being to reduce the proportion of index-linked debt assumed to held by networks to nil. The UKRN guidance and a number of Ofgem's other proposals are based on the principle that the financing structure should reflect that of the notional efficient financing structure for the sector. However that sector is defined, it is unclear how setting the index-linked weighting to nil is consistent with that principle given most if not all network firms hold a proportion of index-linked debt (indeed the notional company's assumed level of index-linked debt increased from 25% to 30% in RIIO-2) or how restricting financing choices to particular debt types secures the most efficient outcome for consumers.

The impact on the financing strategies of networks appears to be acknowledged by Ofgem by the inclusion of three options for managing the transition, reflecting the risk of this policy change harming consumers through inefficient debt costs should the policy be implemented inappropriately.

NGT therefore does not consider the proposal in regard of index-linked debt to be appropriate and as such, does not support it.

Allowed Cost of 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 states that regulators should estimate an allowance for an efficient company under the notional company structure for the relevant sector, with actual debt costs suitably benchmarked against other market evidence.

In RIIO-2, the allowed cost of debt was constructed utilising data from an index of borrowing costs deemed to best align to the sector (Iboxx Utilities 10yr+) and an allowance for additional costs that are not fully reflected in that index output, adjusted to a real allowance using the long-term CPIH assumptions set in RIIO-2.

The cost of derivatives is not included in this assessment of the allowance in RIIO-2, which the UKRN guidance recommends is extended to RIIO-3. This is primarily on the basis that hedging strategies are put in place for a variety of reasons, including individual treasury policies and therefore may not reflect the efficient notional company for the sector. We note an inconsistency with a separate proposal to include the cost of derivatives in calculation of the tax clawback (see FQ20), the basis for the proposal being that this best reflects reality. It appears reasonable to only exclude an instrument if there is evidence that it is not possible to measure its associated costs accurately or that those costs are not relevant to cost of debt.

We understand (and broadly support) the proposed approach to cost of debt but the framework needs to consider the following matters:

- Throughout SSMC and related stakeholder engagement sessions, Ofgem has referred to differentiating sectors depending on the specific investment needs of those sectors and should evidence suggest there is a need to reflect different sector risks in how cost of debt (CoD) is calibrated. At RIIO-2, expected debt costs were based on average costs for the full sector (i.e., the networks with an aligned RIIO timetable, being electricity transmission (ET), gas transmission (GT) and gas distribution (GD)). NGT appointed Economic Insight to assess the most appropriate comparator group for RIIO-3 and its detailed report is appended to our response (chapter 4, "Efficient Cost of Debt for Gas Transmission at RIIO-3"). This work demonstrates there is strong evidence of an increase in risk for gas networks relative to electricity and to RIIO-2, which manifests as a higher cost of borrowing and lower tenures for the gas sector. As such, it is appropriate to assess NGT efficient costs against a comparator group of GT and GD, which provides an appropriate balance of reflecting the divergent risk between electricity and gas and maintaining a comparator that extends beyond NGT alone.

- Following on from Ofgem's Call for Input on the impact of higher inflation issued in August 2023, Ofgem has proposed in SSMC a series of alternative treatments for the use of inflation to adjust the CoD allowance from nominal to real, with the stated objective of removing the so called "leverage effect". As we documented in our response[23] dated 26 September 2023, based on the approach to modelling the impact adopted by Ofgem and the data available at the time, NGT is not forecast to benefit from higher inflation across the RIIO-1 and RIIO-2 period, primarily because its proportion of inflation-linked debt is higher than the sector average and that assumed by the notional company financing structure in RIIO-2. The result is that NGT is likely to be significantly disadvantaged by Ofgem's proposal to reduce the proportion of index linked debt in the notional company financing structure to 0%, which may result in additional costs to the consumer. We expand on this matter in our response to question to FQ3.
- Ofgem also proposes to adjust how inflation is used to set a real allowance. We expand on our analysis of and conclusions on those options in our responses to questions FQ2 and FQ3 below.
- In a further proposed change to the methodology currently in place, Ofgem has proposed an approach to weighting the debt index by annual RAV additions, the stated objective being to protect consumers from compensating network companies raising debt for "financial engineering" purposes rather than investment in infrastructure. Weighting the trailing average to take into account RAV additions may introduce greater stability and predictability, particularly in times of high RAV growth levels, inferring that less regulatory intervention is required, creating greater certainty for networks and perhaps better reflecting the conditions in which networks are raising new debt. However such an approach needs to be carefully calibrated to ensure it reflects when debt needs to be raised to facilitate investment via the combination of this proposal and additional costs of carry etc. as fairly as possible and does not unduly restrict network choice of strategy.
- Analysis carried out by Economic Insight[24] demonstrates that for the comparator set of GT/GD, under the proposed weighted trailing average and the simple trailing average, respectively a 10-year (+0bps additional borrowing costs) and 13 year length (+25bps additional borrowing costs) appears the most appropriate calibration option.

[23] National Gas Transmission Response to Call for Input dated 26th September 2023: [Call for input - Impact of high inflation on the network price control operation | Ofgem]
[24] Economic Insight Report for National Gas dated 4th March 2024 – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 6B

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

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

FQ2 & FQ3 combined:

The three proposals presented (a nominal allowance for fixed rate debt with indexation of the relevant portion of RAV removed, matching indexation for the proportion of RAV linked to fixed rate debt to the long run inflation assumption or retaining the RIIO-2 methodology with an update to the calculation of the assumption used for long-run inflation) are accompanied by a proposal to remove the weighting relating to the proportion of net debt assumed to be index-linked. The logic presented by Ofgem is that this would remove the so-called "leverage effect" when outturn inflation exceeds the inflation assumed when setting CoD allowances.

The impact of these proposals on NGT specifically is analysed later in this question response but a brief assessment of each option is summarised below:

Option 1 – a nominal allowance for fixed rate debt, with indexation of the relevant portion of RAV removed

The key impact of this option is ultimately a higher cost of debt allowance, as cost of debt allowances calculated under the RIIO-2 methodology would be deflated only by the proportion deemed to relate to non-fixed debt in the notional company structure. However, to fully eliminate the leverage effect, Ofgem propose that it is assumed that the notional company holds zero index-linked debt.

This combination of proposals has material disadvantages. Firstly, this option increases consumer bills in the short term as networks will recover a higher proportion of the return through cash rather than RAV indexation.

Ofgem itself estimates this change equates to 5.3% of revenue or a £19 per annum increase across the full sector (or £12 per annum for GT/GD), which is a multiple of the £2.70 (RIIO-2) it estimated as the impact on consumer bills of the recent period of high inflation[25].

Whilst this impact will be neutral over the long run, as lower RAV growth compensates for higher cash in the short term, it is not clear why such an increase is justified to eliminate the leverage effect.

Furthermore, this option removes inflation protection from a significant portion of the RAV. RAV and inflation protection of it is a long established regulatory principle in the UK. The certainty this mechanism provides investors ultimately keeps the cost of capital down. Removing it while leaving the nominal cost of debt granted in its place open to regulatory discretion at each price control could lead to higher systematic risk and a subsequent increase in the cost of capital and consumer bills.

Option 2 – indexing fixed debt portion of RAV using long run inflation assumption

This option means that the portion of RAV that relates to fixed-rate debt under the notional company structure will be indexed using the long-run inflation assumption used to deflate the cost of debt allowances, rather than outturn CPIH as is the case in RIIO-2. The calculation of the cost of debt allowance would not change, although the inflation forecast used to deflate the allowance might.

As with option 1, Ofgem states in SSMC that the leverage effect is only fully removed if the notional company is assumed to have zero index-linked debt.

While this option does not have the significant consumer bill impact of option 1 and does preserve RAV indexation, regulatory discretion and the subsequent impact on systemic risk is still increased. This option requires Ofgem to select a suitable inflation forecast to replace the CPIH currently sourced from the Office for National Statistics, a recognised national statistic. Furthermore, there is no guarantee that the same source of forecast would be used in future price controls, impacting perceived regulatory stability.

Option 1 and 2 – Index-linked debt assumption

As noted above, Ofgem has stated that for options 1 and 2 that it will also review the assumed proportion of index-linked debt for the notional firm, the intention being to fully eliminate the leverage effect.

This proposal appears to violate the principle that regulators should target an efficient capital structure. No evidence is presented that holding index-linked debt is inefficient while evidence from companies' actual financing choices is that holding some index-linked debt is efficient[26]. Indeed, it is logical to assume that investors are attracted to the combination of index-linked debt and an indexed RAV as part of a balanced portfolio.

Option 3 – retain RIIO-2 methodology and reviewing the long-run inflation assumption

This option proposes reviewing and potentially replacing the inflation forecast used to deflate nominal yields used when benchmarking the cost of debt. The benefits and costs of this option are highly dependent on the approach to inflation forecasting. This option does not guarantee that the leverage effect is removed as that is dependent on sourcing a more accurate forecast than that sourced from the Office of Budgetary Responsibility (OBR) that currently provides the forecast used in RIIO-2. Indeed, Frontier analysis shows that CPI has broadly aligned to 2% since Bank of England independence in 1998, which aligns to OBR forecasts[27].

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[25] Economic Insight Report for National Gas dated 4th March 2024 – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 7A Table 4 & 7B pages 31-32 & Ofgem Call for Input – Model: [Call for input - Impact of high inflation on the network price control operation | Ofgem]
[26] Economic Insight Report for National Gas dated 4th March 2024 – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 3C & Figure 2
[27] Frontier Report prepared for ENA – Initial Consideration of Break-even Inflation for Price Control Purposes page 4

The absence of implied changes to RAV indexation does however mean that additional costs expected to arise from options 1 and 2 are less likely.

Ofgem references the use of breakeven inflation[28] as an alternative source of forecast in SSMC. It is not clear from SSMC what analysis Ofgem references to propose this as a better forecast of inflation than the OBR and indeed Ofgem moved away from break even inflation for RIIO-2 in favour of OBR. As detailed in Economic Insight's report[29], there are potential measurement error issues with such an approach and evidence also suggests that historical performance of this approach would have resulted in higher average forecasting errors than OBR forecasts. Frontier reinforces these points in its report noting the difficulty of isolating inflation effects in break even forecast data and forecasting errors[30]. Furthermore, current forecast data implies that 2030 RPI reform is not reflected in forecasts, calling into question the reliability of such forecasts[31].

Whilst not stated in SSMC, we therefore assert that Ofgem should not rule out retaining the use of OBR forecasts, albeit there are opportunities to refine its use with a combination of short-term and long-term forecast lengths (for example, a "composite" index that updates inflation annually through the price control taking into account the latest OBR short run forecasts of CPIH and a longer term view of inflation[32]). Such a mechanism would allow the index used to deflate allowances to track inflation more closely (reducing the leverage effect), would be consistent with regulatory principles and would be relatively easy to implement. As referenced elsewhere in our response, any such index would still need to be based on recognised, publicly available indices to protect regulatory transparency and consistency and further work in this area appears merited before any alternative is selected.

Implementation regime

The impact on financing strategies of networks appears to be acknowledged by Ofgem by the inclusion of three options for managing the transition should options 1 or 2 be implemented, which appears to acknowledge the risk of this policy change harming consumer through inefficient debt costs should the policy be implemented inappropriately. The implementation plans proposed are broadly as follows:

- 10+ year implementation period with the expectation that networks align with the notional structure by the end of that period. The proposal includes the adjustment of the allowances structure in straight line increments
- A set implementation period (example of 10 years is included in SSMC) during which calculation of the debt allowance would be aligned to the actual debt structure and notional gearing. The proposal again include the adjustment of the allowances structure in straight line increments

[28] [RIIO-3 Sector Specific Methodology Consultation – Finance Annex (ofgem.gov.uk)](#) paragraph 2.40
[29] Economic Insight Report for National Gas dated 4th March 2024 – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 7B pages 33-35
[30] Frontier Report prepared for ENA – Initial Consideration of Break-even Inflation for Price Control Purposes page 6
[31] Frontier Report prepared for ENA – Initial Consideration of Break-even Inflation for Price Control Purposes page 7-8
[32] Frontier Report prepared for ENA – Initial Consideration of Break-even Inflation for Price Control Purposes page 5

- Permanently aligning the calculation of the cost of debt granted to the actual debt structure and notional gearing

NGT's experience of the leverage effect

As summarised in our response to FQ1, at the time that NGT responded to the inflation consultation and utilising Ofgem's modelling methodology we were not forecast to benefit from the leverage effect across the RIIO-1 and RIIO-2 periods. NGT's current financial structure is significantly different to the current notional financing structure assumptions in that it maintains a relatively high proportion of inflation-linked debt.

Therefore, in addition to not having benefitted from the leverage effect, NGT would face significant practical issues if it were expected to follow the proposed notional position and transition to holding zero index-linked debt. The natural run off of existing debt, based on existing maturities, stretches to 2053 and therefore the transition would take c.30 years to implement. Given the limited market for RPI-linked instruments and the existing maturities, material premiums are likely to be incurred should NGT be expected to refinance existing agreements before natural maturities. In addition, the maturity profile is not linear, meaning that both the straight-line nature and the term of the proposed implementation regimes would not be appropriate for NGT.

Such an impact would also manifest itself in covenant compliance. NGT's existing banking arrangements have been carefully calibrated to the existing regulatory framework and financial resilience requirements. For example, key ratios such as Adjusted Interest Cover Ratios (AICR) reference coupon rates and cash payments rather than the full accretion impact of inflation. As such, refinancing existing RPI-linked debt for higher coupon fixed rate agreements would be inconsistent with such covenants and likely cause a significant breach.

Furthermore, setting the proportion of index-linked debt used to calculate allowances automatically to companies' actual choices, as would be the case for two of the three implementation options again appears to violate the principle that allowances are set for an efficient notional company. While actual company choices are valuable evidence in assessing the efficient level of borrowing costs, automatically reflecting actual choices in allowances without benchmarking is not consistent with the principles of incentive-based regulation.

In conclusion therefore, it is not clear that any of the options presented offer a clear benefit to consumers. Ofgem's own modelling in the Call for Input demonstrated the impact on consumer bills to be £2.70[33] whereas the options presented have the

[33] Ofgem Call for Input – Model: [Call for input - Impact of high inflation on the network price control operation | Ofgem]() & Economic Insight Report for National Gas dated 4th March 2024 – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 7A Table 4 & 7B pages 31-32

potential to result in more significant addition costs whilst making significant changes to the regulatory framework that appear to violate established principles. Options 1 and 2 also introduce new and potentially complex concepts and mechanisms (such as a blended "real/nominal" WACC in option 1) that are not fully tested and seem at odds with Ofgem's stated objective of simplicity in RIIO-3.

Of the proposals presented in SSMC (assuming the first and second options would be implemented in conjunction with the 0% weighting of index-linked debt) and given these principles, the unusual nature of inflation trends in certain years of RIIO-2 and NGT's experience of the leveraging effect, the only option NGT could logically support is option 3, notably for reasons of practicality and regulatory consistency. This option, of re-assessing the source of the long-run inflation assumption, requires limited changes to existing processes and remains suitable over the long-term (assuming extreme inflation seen in certain years of RIIO-2 was an anomaly, which there is currently no evidence in the forecast options to suggest this is not the case). If selected, the inflation forecast selected needs to align with a recognised, independently published index for reasons of clarity and regulatory consistency and as noted above, may include the OBR forecast currently utilised. Any alternative would also have to be demonstrably better than the status quo to avoid risk to financeability and the credibility of the price control framework.

As stated above, we do not consider setting the index-linked proportion of debt to 0% for the notional company to be consistent with the principles laid out by UKRN or those accepted within the RIIO framework.

However, of the implementation options presented, given NGT's proportion of RPI-linked debt on terms that range from 2037-2053, should this policy be implemented, the third option appears the least damaging option for both the financeability of NGT and consumers, although more clarity is needed on how changes in financing structures would be addressed. This would generate what is essentially a passthrough allowance for debt costs (assuming NGT aligns with notional gearing, which is our current policy) and therefore would need to be accompanied with a benchmarking mechanism to ensue costs are efficiently incurred.

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

See response to FQ3 above. We note again that in our response to the Call for Input on the impact of higher inflation, NGT demonstrated that had not benefitted from the leverage impact and therefore action was not necessary in respect of the experience of the actual company.

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

Ofgem states in SSMC that it proposes to continue to grant additional borrowing costs that could reasonably be incurred by an efficient notional company in the sector within the final allowance for cost of debt. We support this proposal.

Ofgem also states that is not currently considering any further categories of additional borrowing costs from those granted in RIIO-2, which comprise of allowances for transaction costs liquidity/Revolving Credit Facilities, cost of carry and the CPIH issuance/basis mitigation. The latter will include consideration of how to address the planned convergence of RPI and CPIH in 2030.

NGT has, in conjunction with the ENA, commissioned work performed by NERA to assess the additional borrowing costs considered common to all network companies (a full report is appended to our SSMC response; “Additional Cost of Borrowing for the RIIO-3 Price Control”[34]). NERA concludes that the categories of additional borrowings costs are broadly appropriate and presents the latest evidence on how such costs should be set, including certain issues in the application of the methodology used to set them in RIIO-2. The findings are summarised below with full detail included in the appended report:

	Range of costs in bps (midpoint)	**Comments**
Transaction costs	6	Based on updated sector costs
Liquidity/RCF costs	13	Increased costs vs RIIO-2 (4 bps) due to current market conditions. NERA also assume drawdown costs (15%), which Ofgem ignores
Cost of Carry	8-16 (12)	Two inputs: 1) 12-24 month pre-financing, 50% met by RCF 2) company cash and debt in latest RFPR, consistent with RIIO-2 approach
CPI Indexation Costs	18-23 (21)	• 5 bps CPI switching costs also recognised by Ofgem at RIIO-2 • 30-50bps new CPI issuance using latest nominal CPI swap costs and 15 bps for managing CPI-CPI risk based on swap charges • Ofgem ignores CPI-CPH basis risk cost, which is estimated to be 14 bps in SSMC. There are a number of methods of estimating the wedge between CPI and CPIH which warrant further work but we disagree that such a wedge is not material to calibrating cost of debt allowances

[34] NERA Full Report prepared for ENA on Additional Cost of Borrowing for RIIO-3 Price Control

New Issue Premium	5	Latest market evidence and CAA precedent of 15bps NIP, 35% assumed new debt
Additional cost of borrowing	**54-59 (57)**	

Allowed Cost of Equity

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

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

Response to FQ6 and FQ7 combined:

The UKRN Recommendations 2-7 are considered to generally align with the principles of setting such allowances in RIIO-2, being centred on the use of the Capital Asset Pricing Model (CAPM) to estimate the cost of equity with broadly the same methodologies being applied to key inputs such as risk-free rate, equity risk premium and beta. Subject to the assessment of each parameter laid out below and how effectively it reflects the risks facing networks going forward, this approach does not appear inappropriate, but does require Ofgem to consider current market data and wider comparatives than it has in previous price controls.

Ofgem states that it is open to considering new evidence to consider whether this approach adequately reflects the risks networks are facing in the future. A key challenge of this assessment is that the CAPM inherently relies on historical data and on suitable listed comparators to provide data on beta in particular. As such, Ofgem may need to consider evidence provided by data on additional listed companies or additional cross checks not considered in RIIO-2. The consideration of cross checks to sense check the midpoint of assessment of a CAPM range is consistent with UKRN Recommendation 7 and we expand on results of work performed in this area later in this section.

Risk Free Rate

Ofgem utilised the one-month (October, daily) average of a 20-year index-linked gilt for RIIO-2 and is proposing to utilise the same input for RIIO-3. Again, as in RIIO-2, it is proposed that the risk-free rate is updated annually during the RIIO-3 period.

As index-linked gilts are "RPI-real" instruments, to be utilised as a proxy for the risk free rate, yields must be adjusted to "CPIH-real", which is achieved by estimating the difference between RPI and CPIH inflation (the "wedge"). Given RPI and CPIH will essentially converge in 2030, Ofgem proposes to estimate this wedge using HM Treasury or OBR forecasts of CPI and RPI to the assumed point of convergence (February 2030) and a zero wedge thereafter. Despite historical CPI and CPIH between June 2013 and June 2023 varying by 14 bps[35] (para. 3.39 of SSMC), Ofgem proposes to use CPI as a proxy for CPIH.

Based on our analysis and the work performed by Oxera on behalf of the ENA ("RIIO-3 Cost of Equity"[36]), it is NGT's view that:

- The use of 20-year index-linked gilts and an update to the rate on an annual basis is appropriate as a starting point
- We acknowledge that Ofgem states in SSMC that it will not be considering additional proxies for the risk free rate for RIIO-3, a position largely based on being proven to be "not wrong" by the CMA at RIIO-2 appeals, although it should also be noted that the CMA has also concluded on several occasions that AAA-rated non-government bonds have an exceptionally low risk of default. There is precedent for additional proxies being considered by other regulatory bodies, including the CMA and the Civil Aviation Authority. Reference should be made to the evidence provided by AAA-rated non-government bonds in estimating the risk free rate. As detailed in Oxera's report[37], it had been observed that the yield on the highest-rating corporate bonds is usually higher than the yield of government bonds on the same maturity and also below the returns on a zero-beta asset given the special properties of and demand for government bonds (referred to as the "convenience premium"). To arrive at a true risk free rate, an adjustment is therefore required to remove this convenience premium. The inclusion of data from iBoxx AAA indices is therefore proposed and supported by NGT. We further note that whilst we agree with the UKRN guidance that starting with 20 year index-linked gilts is an appropriate starting point, given the average duration of constituents of the AAA-rated indices (10-13 years) and the average remaining life (13-30 years), the UKRN guidance does not prevent their use and such terms are well within the 10-20 CAPM investment horizon common to regulatory determinations.
- Estimates of the wedge between RPI and CPIH should reference the following as well as the OBR-sourced "20 year inflation forecast" expected to be utilised by Ofgem[38]:
    - Estimation of the RPI-CPI wedge based on swap rates
    - The wedge between CPI and CPIH should not be ignored. Such an exclusion risks underestimating the RPI-CPIH wedge and subsequently the RFR.

[35] RIIO-3 Sector Specific Methodology Consultation – Finance Annex (ofgem.gov.uk) paragraph 3.39
[36] Oxera - RIIO-3 Cost of Equity prepared for ENA as available in Appendix
[37] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.1.1
[38] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.1.2

Updating the methodology and inputs as described above would result in a risk free rate of 1.84% vs 1.32% should the current approach employed by Ofgem continue to be adopted.

Total Market Return (TMR)

TMR is used to estimate the Equity Risk Premium (ERP), the additional return over the risk free rate that investors expect for taking the market average level of risk. In RIIO-2 ERP is calculated as the difference between TMR and the risk-free rate, an approach Ofgem proposes retaining in RIIO-3.

TMR is typically estimated using long-run historical averages of relevant broad equity indices as the best proxy for long-term future expectations. While some regulators have taken into account future-looking estimates, UKRN guidance recommends that TMR should be primarily based on historical ex-post (observable historical returns) and ex-ante (historical returns adjusted for unexpected events) evidence. Ofgem proposes to use long-run historical returns and to consider a range of timeframes, averaging methodologies and potential adjustments to order the use of historical data to arrive at a forward-looking estimate of TMR. This will place weight on both ex-post and ex-ante inputs, although at RIIO-2 it was not clear how such evidence was weighted by Ofgem.

Such returns need to be adjusted to real returns and therefore a suitable inflation index must also be adopted by Ofgem in setting TMR. Ofgem proposes using the Consumption Expenditure Deflator for the period 1900-1949, backcast CPI/CPIH data for the period 1950-1988 and Office of National Statistics data for CPI/CPIH from 1988 onwards.

Based on our analysis and the work performed by Oxera on behalf of the ENA ("RIIO-3 Cost of Equity"[39]), it is NGT's view that:

- We see no strong evidence for amending the broad methodology applied to estimate the ERP
- The CPIH backcast data[40] for 1950-1988 period should be utilised given errors in the previous release have now been addressed but otherwise Ofgem's use of the proposed inflation indices appears reasonable
- Whilst we recognise the UKRN Guidance that both ex post[41] and ex ante[42] returns data is assessed, limited weight should be placed to the ex-ante dataset, given its subjective nature driven by adjustments made for unexpected events. An arithmetic average should be utilised to average historical returns

[39] Oxera - RIIO-3 Cost of Equity prepared for ENA as available in Appendix

[40] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.2.1 – Treatment of inflation
[41] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.2.2
[42] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.2.3

In respect of the overall determination of TMR, Oxera has also analysed what the recent increase in interest rates implies for TMR[43]. The UKRN Guidance did note that UK regulators have assumed greater stability in the TMR than ERP and that continuing with that approach is preferable, which Ofgem also emphasises. The UKRN does however also point out that regulators should not simply select the same fixed value for TMR in each price control, but that the TMR would be relatively less variable than the RFR.

Oxera's analysis demonstrates that TMR allowances were reduced in the period 2010-2021 in response to a decline in gilt yields[44]. Since 2022 gilt rates have sharply increased to levels last seen in 2005-11, when TMR was set at 7.0%-7.25% (RPI real), which implies that a consistent approach would result in an increase in the TMR assumption in RIIO-3 (RPI-real estimates of 7.0%-7.25% would equate to between 8.07%-8.32% in CPIH-real terms). We also note Frontier's analysis in chapters 2.1-2.3 of its report "Equity Investability in RIIO-3"[45] which further supports the link between regulatory decisions and trends in index-linked gilts and interest rates and goes onto conclude that changes in recent capital markets cannot ignored, particularly at a time of heightened risks for networks. Frontier goes onto conclude in chapter 4.2[46] that the UKRN guidance ask regulators to ensure that TMR is "stable but not fixed" and that Ofgem will need to take a view on the extent to which it needs to increase its RIIO-2 estimate of TMR, but a c.3.5% increase in gilt yields since RIIO-2 implies it should be material.

Oxera concludes that an update to the methodology and inputs as described above would result in a TMR range of 6.5% to 7.5% vs 6.25% to 6.75% should the current approach employed by Ofgem at RIIO-2 continue to be adopted. Such a range only reflects 15% of the increase in gilt yields since RIIO-2 and therefore whilst the UKRN's view that TMR is "less variable" than RFR, such evidence suggests TMR should be increased further (see also Frontier's report prepared for the ENA, "The Low Beta Puzzle")[47]. Indeed, as summarised later in this section, the ARP-DRP cross check Oxera has also analysed corroborates a TMR estimate of 7.5% to derive a suitable risk premium for cost of equity, whereas a consistent approach with the last period of similar levels of gilt rates would imply a TMR of c.8% as summarised above.

Beta

Beta is used as an estimate of the risk specific to an investment that cannot be diversified away ("systematic risk"). Asset beta, the systematic risk of investing in an asset, is made up of equity beta (the exposure of shareholders to systematic risk) and debt beta (the same for debt investors), weighted by an appropriate level of gearing.

[43] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.2.4
[44] Oxera - RIIO-3 Cost of Equity prepared for ENA Figure 2.6
[45] Frontier Report prepared for ENA – Equity Investability in RIIO-3 Chapter 2.1
[46] Frontier Report prepared for ENA – Equity Investability in RIIO-3 Chapter 4.2
[47] Frontier Report prepared for ENA – The Low Beta Puzzle in RIIO-3

Ofgem proposes to retain the approach taken in RIIO-2, which is deemed to be in line with UKRN guidance. This can be therefore based on Ordinary Least Squares regression analysis, as recommended by Ofgem in SSMC Finance Annex paragraph 3.67, of relevant listed comparators, de-gearing data to make asset beta comparisons before re-gearing to the notional capital structure.

In RIIO-2, comparators firms were limited to listed UK energy and water networks. Whilst Ofgem remains of the view that these firms are more representative of the risks faced by UK energy networks, it does state in the SSMC that should evidence suggest that data on other comparators, or a different weighting of existing comparators present more accurate reflections of the risks facing network in the future, it will consider it.

Based on our analysis and the work performed by Oxera on behalf of the ENA ("RIIO-3 Cost of Equity[48]"), it is NGT's view that:

- In RIIO-2, the only betas measured were those derived from a sample of four companies, being National Grid, Pennon, Severn Trent and United Utilities. National Grid is considered a good comparator as it is the only "pure play" energy company in the sample and as such, a 70% weighting was applied to its beta in RIIO-2. However, even National Grid has increasing proportion of its business invested in electricity distribution (since its acquisition of Western Power Distribution, now known as National Grid Electricity Distribution, in June 2021) and in the US. Furthermore, since its disposal of a majority share in its gas transmission business (now National Gas Transmission) in January 2023 it has less exposure to gas. As detailed in Oxera's report[49], we support the inclusion of certain European comparators to generate a suitable sample, particularly in respect of the gas sector. The networks proposed have been selected based on percentage of regulated activities, data availability and liquidity. Even extending the beta comparator sample still results in a limited pool of comparators for the gas sector. As such, the results of cross checks summarised later in our response to this question should be carefully considered by Ofgem, particularly where evidence from debt markets indicate the presence of risks not yet shown by beta data (see ARP-DRP)
- Ofgem has in the past referenced 2 year, 5 year and 10 year estimation windows to derive beta. If equally weighted, recent observations are accounted for multiple times[50]. Furthermore, given National Grid's divestment of gas distribution between 2017 and 2019 and its divestment of a majority share of NGT in 2023, longer-term estimates of National Grid betas would better represent both electricity and gas risk. However, we do note Frontier's comments about the importance of this judgement given periods of volatility within these timeframes and the consequences of reliance on timeframes likely to be impacted by estimation issues, implying further work may be necessary[51]. As referenced in the TMR section of our response

[48] Oxera - RIIO-3 Cost of Equity prepared for ENA as available in Appendix
[49] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.3.1
[50] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.3.2
[51] Frontier Report prepared for ENA – The Low Beta Puzzle in RIIO-3 page 6 & Chapter 3

to this question, given these concerns Ofgem may need consider whether its overall assessment of CoE is sufficient when judgements on beta and TMR are taken together and results of cross checks are considered.

At the time of responding to SSMC, updating the methodology and inputs as described above would result in a beta range of 0.7 to 0.82, the same as utilising Ofgem's approach. That being said the principles behind the inclusion of additional comparators and their respective weightings remain valid and should be considered carefully for the RIIO-3 price control.

Taking into account the assessment of risk free rate, TMR and beta and a data cut off point of 20 December 2023, at 60% gearing the indicative CoE range according to Oxera's analysis would be 5.08% to 6.48%, with a midpoint of 5.78% (CPIH-real, 60% gearing) vs Ofgem's approach of 4.75% to 5.77%, midpoint 5.26% (also CPIH-real, 60% gearing).

Use of cross checks

UKRN Recommendation 7 suggests the use of cross checks to sense check the overall Cost of Equity derived from the CAPM derived midpoint but that the midpoint should only be deviated from if there are strong reasons to do so. Ofgem agrees with that recommendation and proposes to adopt it in RIIO-3.

NGT supports the use of cross checks to sense check the overall Cost of Equity. As such, the detailed report from Oxera referenced earlier includes an assessment of the ARP-DRP cross check. Frontier Economics has also been commissioned by the ENA to perform an assessment of a series of cross checks, including those utilised by Ofgem in RIIO-2 or proposed in SSMC. The methodologies employed in performance this assessment are summarised below:

- ARP (Asset Risk Premium)-DRP (Debt Risk Premium) differential
- Hybrid bond inferred cost of equity
- Equity IRR implied by evidence from infrastructure funds
- Investment managers' forecast of TMR
- Fernandez survey of total market returns
- Long-term profitability benchmarking

Frontier has also analysed evidence currently available regarding the MAR implied CoE cross-check but it is not yet possible to draw meaningful conclusions.

The objective of such cross checks is to enhance the robustness of the estimate derived from the CAPM, which is particularly important at a time when networks face unprecedented risks in future and risks that are may not be reflected in historical data used to estimate CAPM. The outcome of these cross checks and additional refinements to beta data utilised should be considered by Ofgem to ensure a balanced estimate of the risks facing network in future is arrived at.

ARP-DRP cross check

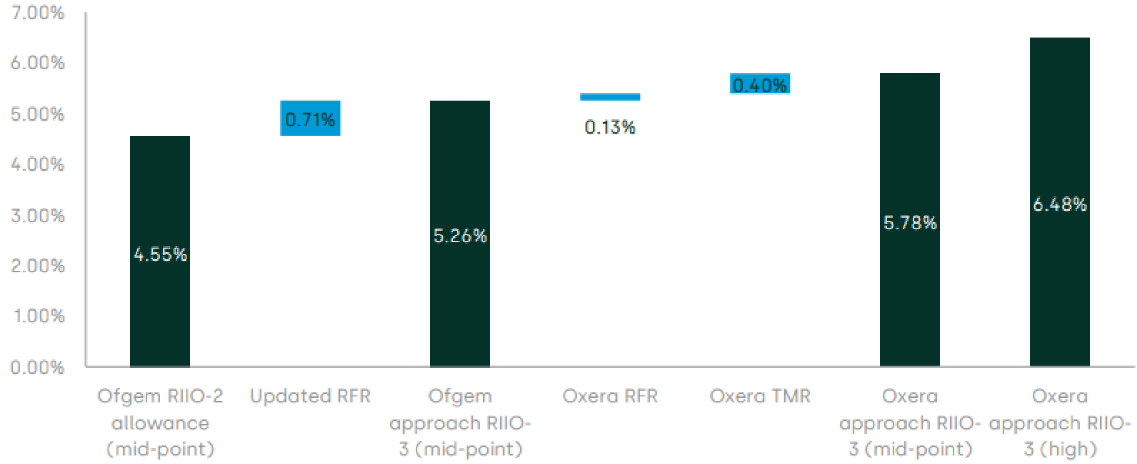
The detailed report from Oxera[52] explains how the cost of debt can be used as a benchmark of cost of equity estimates by comparing a measure of the ARP with the DRP. This is a reliable cross-check method of whether the allowed cost of equity is appropriately calibrated by evidencing market data on observed borrowing costs rather than being built up from a theoretical asset pricing model. The report emphasises that as debt holders have priority claims ahead of equity investors over a company's assets, equity investors are subject to greater risks and demand a higher return. Where this principle is breached by cost of equity estimates being too low relative to the market pricing of debt, this suggests an error in the application of the cost of equity estimation.

Oxera has carried out the cross-check analysis by using the methodology Ofgem are assumed to have applied to RIIO-2 and their CAPM-based analysis approach to estimate a RIIO-3 cost of equity allowance. According to their findings, as noted previously the cost of equity range generated by rolling forward the RIIO-2 methodology (as Ofgem proposes) is 4.75-5.77% (at 60% gearing, CPIH-real), with a mid-point at 5.26% compared with 5.08–6.48% (at 60% gearing, CPIH-real), with a mid-point at 5.78% when applying Oxera's approach. The difference is explained by higher TMR and RFR estimates. According to Oxera's conclusion, the ARP-DRP cross-check further suggests that the appropriate point estimate should be towards the upper end of the range. We acknowledge the UKRN Guidance and decision included in Ofgem's Framework Decision regarding "aiming up" within a range, but Oxera's analysis of the relationship between TMR and interest rates notes that recognising the same pattern, as summarised in our section on TMR earlier in this response, the TMR allowance should be set around the level of 2005-11, as interest rates in RIIO-3 are expected to be approximately at similar levels to those years. We also note Oxera's analysis of and response to recent CMA discussions regarding the application of ARP-DRP as a cross check.[53]

The cost of equity estimates are summarised in the below figure with the impact of the differences in each parameter.[54]

[52] Oxera - RIIO-3 Cost of Equity prepared for ENA Section 3
[53] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 3.1.1
[54] Oxera - RIIO-3 Cost of Equity prepared for ENA Figure 4.1

Figure 4.1 The impact of individual methodological choices on Ofgem's and Oxera's CoE estimates (CPIH-real)



Note: The mid-points are calculated as averages of the low and high CoE scenarios, rather than the average of each specific CoE parameter. The quantification of the impact of the change in individual parameters is indicative, as it depends on the sequence in which adjustments of individual parameters are performed. Minor discrepancies may occur due to rounding. The estimates do not separately account for the forward-looking sector-specific risks.
Source: Oxera analysis.

Frontier has been commissioned by the ENA to carry out cross-check analysis of the output of CAPM by utilising a series of methods. Frontier specifically focused on hybrid bonds to infer required equity returns alongside with testing evidence related to cross-check approaches utilised by Ofgem for RIIO-2 and other cross-checks e.g., Fernandez UK TRM estimate and long-term profitability with the latest available evidence.

Hybrid bonds

Frontier's rationale to focus on hybrid bonds is that such instruments blend characteristics of both debt and equity[55]. Assuming the allocation of these securities between debt and equity stands at 50% (as assumed by credit rating agencies), the spread between the expected return on hybrid bonds and conventional senior debt would fall at the midpoint between equity and senior debt costs. Among the GB hybrid bond options analysed by Frontier, evidence from NGG June 2073 hybrid was selected, given its longest time-to-next call and to avoid currency exchange complications. According to the result of Frontier analysis, the spread between the expected return on this hybrid and the corresponding IBoxx at the time of issue is estimated to be 136 bps, which in turn infers a point estimate for the implied cost of equity of 6.7% CPIH-real.

[55] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 3.1.1 - 91-94, Section 4 - 112 & Section 5

Market-to-asset ratios

Ofgem utilised this cross check at RIIO-2 to infer that the allowed cost of equity was sufficient based on "traded MARs", being the ratio of the regulated enterprise value (EV) and the regulated asset value (RAV) of each company. Frontier has updated the analysis of traded MARs[56], albeit an updated analysis of transaction MARs has not been possible given the lack of transactions. This analysis demonstrates a significant reduction in MARs since Ofgem's assessments in RIIO-2. According to the findings, the current market suggests a range of 10%-15% whereas Ofgem's RIIO-2 analysis inferred a range of 20%-60%. At this stage of the price control process, Frontier has not used these MARs to derive an inferred CoE. However, it is clear that all MARs have fallen since RIIO-2 and as such, the conclusions reached then are not supported by current information.

Infrastructure fund implied equity IRR

Frontier references objections raised to this cross check at RIIO-2 but has updated evidence on the discount rates for 10 of the 13 infrastructure funds[57] considered by Ofgem in RIIO-2, which demonstrates that the average equity implied IRR has increased from c. 5.9% in July 2020 to c. 9.6% in December 2023.

Investment managers forecast of TMR

Despite concerns about the nature of the output of this cross check, Frontier has also updated evidence for UK TMR forecasts for the discount rates for 7 of the 11 institutions[58] that Ofgem utilised at RIIO-2. According to Frontier's update, the average of all forecasts has increased from 6.9% in July 2020 to 8.7% in December 2023. Furthermore, 6 of the 7 forecasts have increased between 2020-2023 evidencing a TMR increase by a range of 0.7%-5.4%. Replicating Ofgem's application of a beta of 0.9 at RIIO-2 with an updated risk-free rate implies a cost of equity of 6.04% CPIH-real.

Fernandez survey

Frontier's report also contains details of the annual survey of risk-free rates and market risk premium conducted by Fernandez et al[59]. TMR evidence from this survey combined with the same beta and risk-free rate assumptions noted above implies a cost of equity of 7.2%%.

[56] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 6.4.1
[57] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 6.4.4
[58] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 6.4.3

[59] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 6.4.3

Long term profitability

In addition to the above cross-checks, Frontier also looked at long-term profitability as a cross-check[60]. Ofgem did not reference long term profitability as a cross check at RIIO-2 but given the focus on investability it has been included in Frontier's analysis. Frontier used Bloomberg data for the return on common equity for utility sector indices and a set of four EU and five US comparator utilities. The results of an arithmetic mean calculation applied to return on common equity for these utilities and indices over a period of 22 years (2002 to 2023) are a range of 5.9% to 17.5%, which low and median estimates of 5.9% and 8.4% respectively.

Frontier concluded from the outcome of the analysis that the range in values of the return on common equity is large and appears to be positively skewed. Therefore, based on low and median estimates which provide good coverage of the sample selected, a reasonable range for this cross check is considered to be between 5.9%-8.4%.

Conclusion on cross checks

The work performed by Oxera and Frontier on cross checks all infer that the Cost of Equity midpoint generated by the CAPM methodology is not sufficient to fully reflect the risks facing networks and changes in capital market conditions. Ofgem should therefore consider the evidence from such cross checks when assessing how UKRN Recommendations are applied in the RIIO-3 price control and whether the range of estimates applied to each input to CAPM are truly reflective of current and forward-looking risks, notably those for beta and TMR.

Outperformance wedge

It should also be noted that the inputs to CAPM should be assessed using the principles laid out in SSMC and the analysis performed by network firms and their supporting consultants, none of which includes an adjustment for historical performance of network firms (the "outperformance wedge"). Such a mechanism was deemed "wrong" by the CMA at RIIO-2 and was also not proposed at RIIO ED2. We welcome Ofgem not including an outperformance mechanism in RIIO-3. Allowed Returns, incentive packages and totex allowances should be assessed and set using the extensive set of tools Ofgem already has access to and should reflect the relevant activities of each network and the risks taken in delivering those outcomes. Depending on the evidence available using CAPM and appropriate cross checks, it may be that the Allowed Return does not fully represent the risks faced by network firms and therefore other reflections of an appropriate balance of risk and returns between investors and consumers, such as incentive packages, may need to be considered. To that end, we understand Ofgem's proposal that the expected outcome of a price control is assessed "in the round".

[60] Frontier Report prepared for ENA – Equity Investability in RIIO-3 paragraph 6.5.1

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?

See responses to FQ7.

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?

See responses to FQ7.

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?

UKRN recommendations generally align to the approach followed in RIIO-2, that being to set WACC based on an efficient notional company including a gearing assumption. This leaves flexibility to networks to set their own financing strategies within the bounds of wider financial resilience requirements. Subject to the points made in our responses to questions FQ1-9, NGT generally supports this proposal. We again refer to our comments in responses to those questions on the risk of undermining these principles, particularly through proposals relating to assumed proportion of index-linked debt and implementing inflation proposals.

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?

As noted elsewhere in our responses, NGT generally supports the principle that the notional financing structure should reflect that of the efficient capital structure in the relevant sector. Gearing levels and the mix of debt types applied to the notional company should continue to reference the sector experience.

A further high level assessment of appropriate evidence in this regard is provided in Economic Insight's report[61] appended to this report, which implies that the RIIO-2 level of regulatory gearing continues to be broadly appropriate.

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?

As noted in our response to question FQ11, setting the notional gearing should reference the financing structure of the notional efficient company in the relevant sector. The notional firm should be assessed using appropriate empirical evidence and cross checks to ensure consistency with other aspects of the price control, an important reference point of which should be actual choices of firms in the sector given the incentives in place to optimise capital structures.

It therefore seems appropriate for practical reasons to set to the notional level of gearing at the beginning of the price control period. In doing so, Ofgem would also provide an element of consistency and predictability to networks and investors, not to mention simplicity.

Financeability

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

Ofgem has a duty to allow networks to recover revenues that are sufficient to pay interest and dividends to finance providers (Ofgem powers and duties 1.6 "the need to secure that licence holders are able to finance the activities which are the subject of obligations on them"). NGT has a financeability duty set out within the RIIO-GT2 licence to ensure an investment grade credit rating is maintained.

Optimising the efficiency of financing costs requires maintenance of a strong credit rating and provision of confidence to investors that their investment is secure. The financeability assessment should therefore be a review of the projected levels of a range of financial ratios relevant to both debt and equity investors. These ratios should be further tested under a series of macroeconomic and performance scenarios.

Ofgem has proposed a range of measures and methodologies which could be used to extend the financeability assessment used in RIIO-GT2. We agree that the financeability assessment should be enhanced to take a more holistic view and comment on Ofgem's proposals as follows.

Ofgem's focus is on the financeability of the notional company. We agree with the assessment of financeability for a notionally efficient company with a capital structure consistent with that used to determine the weighted average cost of capital. This ensures companies and their shareholders bear the risk of their capital structure and financing, not customers.

Ofgem's proposed approach to debt financeability is similar to RIIO-2; to be assessed "in the round" using the notional entity and reference to achieving a "comfortable" investment grade credit rating. This will again be based on Moody's methodology and does not appear inappropriate. Comfortable investment grade credit quality is not further defined in the SSMC. However, this is strongly linked with the financial resilience requirements set out in Standard Special Condition A38 of the GT licence, which currently states that the licensee must use reasonable endeavours to maintain an investment grade credit rating (defined as Baa3 under the Moody's methodology), with additional financial resilience reporting being required should this credit rating be withdrawn or a negative rating action issued. The requirement to provide additional reporting in these circumstances (i.e. rating falling to Baa2 with a negative watch or lower) supports the notion that a rating of Baa1 under the Moody's methodology is akin to a "comfortable" rating.

[61] Economic Insight Report – Efficient Cost of Debt for Gas Transmission at RIIO-3 Chapter 3B

With regards to the methodology selected to assess credit ratings, we do not see a reason to depart from the Moody's methodology given it has the more transparent and replicable methodology of the agencies currently relied upon. NGT also supports retention of a target credit rating of Baa1 under this methodology, as noted above. The cross-checks we have considered are referenced in our response to Ofgem suggests the financeability assessment is extended beyond debt investors to take account of wider investability. We support this enhancement as it is more reflective of the capital structure and financing costs of the licensee. SSMC is however written assuming that a significant increase in investment is required in the ET sector, inferring that the same challenge does not apply to the GT sector. Key drivers of NGT's investment plan for the RIIO-3 period, such as the requirement to maintain a resilient network at a level of risk consistent with the end of the RIIO-2 period and an uplift in the mandated levels of cyber and physical security standards, mean that NGT's investment plan requires more investment than RIIO-2. As such, NGT will need to be able to attract additional investment in the next price control period if these crucial investment drivers are to be met.

Ofgem lists a number of potential options for improving the assessment of financeability and the wider concept of investability in SSMC, including a longer-term assessment (generally limited to price control period in review at present), additional credit ratios and broader indications of equity cost such as dividend yield expectations. Additional financeability levers are also referenced, such as changing asset lives or capitalisation rates. As noted elsewhere in our response, whilst we understand that such levers can have a favourable impact on financeability, they can also cause long-term issues when used to address short-term financeability issues. These levers should not therefore be enacted to support a return deemed inadequate to attract investment and should instead reference the underlying principles of how such parameters should be defined.

Ofgem also sets out the application of scenario analysis to the initial financeability assessment. Again, we are in agreement with this enhancement and we would be interested to hear from Ofgem on what scenarios networks would be expected to test. Financeability is not just a consideration of short-term liquidity ratios but considers the long-term sustainability of the company's financial position under a range of macroeconomic and investment scenarios. Taking a long-term sustainable approach also ensures investment is recovered fairly from both current and future consumers and avoids short-term fixes to address immediate cashflow issues that might create financeability problems in the future.

Ofgem states the intention that financeability will be tested against baseline totex allowances and scenarios where there could be additional totex allowed through variant ex-post expenditure. We agree that a range of possible investment scenarios should form part of the assessment to ensure appropriate resilience, particularly given the uncertainties that exist around natural gas usage scenarios and the impact of new business models such as hydrogen and CCS. Existing financeability obligations centre on the licensee itself and therefore the presence of hydrogen investment in the same entity (a realistic scenario given the opportunity repurposing presents, see FQ21-23) may necessitate analysis of scenarios outside of the natural gas-only scope of RIIO-3.

We also need to retain sufficient financial capacity and flexibility to continue operations and investment programmes in the event of a range of economic scenarios and outturn of downside risk.

We support Ofgem’s view that financeability could be subject to longer term analysis, including a review beyond the current price control period to highlight the long-term sustainability of the financial package. This approach is consistent with Ofgem’s primary obligation of ensuring fair charges for existing and future consumers for the networks they use and the services they receive. It also removes adopting short-term fixes which could have the unintended consequence of increasing overall costs by bringing cash forward to address financeability issues in RIIO-GT3 and deferring underlying issues into the next price control period.

In summary, we note that paragraph 5.15 of the SSMC Finance annex refers to the Framework Decision to “not consider 'aiming-up' of the allowed return on capital” and instead “In the event financeability constraints are identified, [to] consider a number of financeability 'levers'”. As summarised in or response to FQ7, whilst we note the relevant UKRN guidance that informs the Framework Decision, we reiterate that the data considered in forming an estimate under the CAPM methodology and use the relevant of cross-checks to sense check this result should be assessed against the relevant principles to ensure that the result represents a return that adequate to attract investment to the sector and support its ambition. As also noted in FQ7, this will require Ofgem to consider additional evidence to ensure forward-looking risks facing the sector are adequately reflected in the allowed return. Additional levers, whilst having a positive impact in the near-term potentially undermine long-term financeability and should not be used to support an inadequate return. We also reiterate that financeability and investability should consider the financial package in the round, as Ofgem itself proposes, and this may require a wider assessment of where in that package the appropriate balance of risk and return between customers and investors is reached and should include areas such as incentive packages.

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

Macro-economic factors have changed since the RIIO-2 parameters were set, notably in respect of Bank of England interest rate expectations and the cost of lending, both of which now look set to remain at higher levels for the foreseeable future. Subject to points we have summarised in our responses to FQ1-5, particularly in respect to how proposed inflation methodologies are implemented, existing mechanisms for setting the cost of debt should capture reasonable debt costs and ensure they are compensated.

However, increases in the observable cost of debt raised question about the level of returns equity investors require in order for networks to attract the appropriate blend of funding, the risk being that the wedge between allowed cost of debt and cost of equity shrinks to the point that the rationale for investing in equity becomes unclear.

Ofgem has recognised this risk in SSMC and as we note elsewhere, we support this wider assessment of financeability, particularly its focus on retaining and attracting equity investment. We reference both retaining and attracting equity investment as both will be crucial in facilitating stakeholder driven network investment plans over RIIO-3.

We consider cross checks of the outcome of CAPM to be the most appropriate measure of investability as they provide evidence of market expectations and an opportunity to capture evidence that an inherently backward-looking CAPM approach may not. The cross checks we have considered in conjunction with the ENA are summarised in our response to FQ6/FQ7 and imply that a roll forward of the CAPM principles employed in RIIO-2 is not sufficient. As summarised by Frontier in its report[62] appended to our response, both the methodologies utilised by Ofgem in RIIO-2 and new methods proposed by Oxera or Frontier demonstrate a range higher than rolling forward the RIIO-2 methodology would imply. Given this result, as noted in our response to FQ6/FQ7, this points to a requirement to further consider what the CAPM midpoint is missing and evidence contained in Oxera's report[63] demonstrates that TMR, notably what both higher interest and gilt rates implies, is the most appropriate input to re-assess.

Furthermore, the investability assessment should consider:

- A longer-term assessment of financeability that it not just limited to the next price control period, particularly where adjustments to financing parameters have moved cash forward from future price control periods
- Should financial resilience measures be implemented, sufficient coverage of key ratios employed by chosen rating agencies to ensure the interaction of the proposed financial package and rating agency approaches is fully understood ahead of the price control
- Stable cash characteristics that allows for debt servicing and a dividend yield that appropriate reflects market evidence
- Wider indicators of an appropriate balance of risk and return being reached between networks and consumers such as how incentive scheme caps and collars are calibrated and potentially the calibration of cost efficiency challenge based on projections of productivity.

We also note that RIIO-3 plans in the scope of SSMC reflect investment in the natural gas transmission network only. There are scenarios elaborated on elsewhere in our response where the same licensee may be responsible for constructing and maintaining networks under other regulatory frameworks, such as the Hydrogen Transportation Business Model or the equivalent for storage or CCS activities. It is not yet clear how the financeability requirement for licensees in these circumstances will be addressed and therefore such assessments may need to be extended or re-run at the appropriate time.

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[62] Frontier Report prepared for ENA – Equity Investability in RIIO-3 Executive Summary – paragraphs 10-18

[63] Oxera - RIIO-3 Cost of Equity prepared for ENA paragraph 2.2.4

Furthermore, as noted elsewhere in our submission, a number of proposals include changes to established regulatory principles, notably in the proposed options for inflation and cost of debt allowance calculation. Where such proposals violate principles and undermine investor confidence, they may also undermine investability assessments. The same may apply to changes to finance parameters, such as gearing, asset lives or notional dividend yield, used as a short-term financeability "fixes" based on limited evidence and at the cost of long-term stability or financeability.

Finance 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?

Ofgem recognises in SSMC that it already has in place a suite of tools and reporting that allow it to monitor the financial resilience of network companies and NGT has complied with these during the RIIO-2 period. Financing and dividend policies in particular are aligned to the licence obligations NGT has, notably the need to deliver investments agreed with Ofgem and to perform its unique role on the network. Ofgem itself recognises that these "have been broadly effective in helping incentivise shareholders and management to maintain financial policies and outcomes that are consistent with a financially resilient sector".

However, we do recognise that the risks energy sectors are facing are evolving and this consultation should reflect on whether resilience measures are appropriate going forward. In respect of the specific requirements consulted on in SSMC:

- NGT already holds two investment grade credit ratings and does not disagree that reducing the reliance on one credit rating agency's approach benefits network companies' and Ofgem's assessment of financial resilience. We do not support the removal of the term "reasonable endeavours" given the risk of a licence breach caused by factors that may be outside of a network firm's control. We would request that the implementation of any such recommendations clarifies the consequences of one credit rating slipping into a negative outlook while the other remains at a "comfortable" investment grade rating (i.e., would this trigger enhanced resilience reporting?). We would also welcome clarification of how resilience requirements interact with ringfencing requirements of the existing licences, notably the requirement for other entities that have loan relationships with the regulated entity to hold an investment grade credit rating while the loan is in place (i.e., will those entities also be required to hold more than one rating?). Such knock-on consequences of these proposals may create onerous requirements that are disproportionate with the risks that the proposals aim to address.
- Assuming the proposed refers to the regulated business, dividend lock up requirements of 80% regulatory gearing or BBB- credit rating reflect a fair level at which it could be reasonably expected that cash should be retained within the regulated business. Such a level of gearing is also not consistent with an investment grade credit rating under the Moody's methodology

- Whilst the proposed extension of the assessment period for Availability of Resources reporting purposes goes beyond the requirements of Company Law (minimum of 12 months from approval of accounts), a responsible business should maintain forecasts for an appropriate period to support such an assessment and recognise the additional visibility it could provide Ofgem should the associated information requirement be defined correctly. We do request clarification on how assessments should be performed later in the price control period when periods under review stretch into future price controls, in particular the financial parameters that should be assumed in such an assessment.

Any changes proposed need to reach a fair balance between appropriate insight and early warning of issues whilst ensuring that restrictions do not unduly influence the choice of financing structures and flexibility that allows network firms to attract investment to the sector. As noted in the introduction to the Finance Annex, transmission and distributions networks have not faced the same issues as encountered in other sectors and an imbalance towards more restrictive requirements has the potential to undermine investability.

In parallel to this response, we have provided comments or requests for clarification to Ofgem's separate consultation on the FY24 RFPR (comments on "RIIO-2 RFPR – Regulatory Instructions and Guidance version 3.0_draft"). In particular, as noted in our response to FQ17, financing and dividend policies depend on multiple factors and are inherently complex. NGT's dividend policy references a number of factors but key determinates of the levels of dividends paid are existing resilience measures (i.e. gearing and the subsequent impact of the tax clawback mechanism if gearing levels are exceeded), the investment of requirements of NGT as a whole (taking into account all businesses, not just natural gas), performance of the various business units within NGT (including unlicenced activities) and ensuring it has sufficient facilities available to fulfil its licence obligations (i.e. balancing, shrinkage purchases etc). We are not aware of any external benchmark that allows comparison of the level of NGT dividends given the number of factors at play for both and NGT and other regulated businesses, even if a direct comparator for NGT could be identified.

Furthermore, certain requirements should be clearly defined, particularly where disclosures regarding entities related to the regulated entity are proposed, as the wording currently included is in certain aspects ambiguous and open to interpretation.

We also note that certain disclosures relate to information not in the public domain and as such will be redacted in accordance with paragraph 4.13 of the proposed RFPR guidance for both dividend policies and financial resilience requirements. The terms of 4.13 should therefore be clearly extended to dividend policies.

Subject to these points in our response to Ofgem's separate consultation on changes to annual reporting commencing from the FY24 period, the points of clarification and assuming requirements continue to reference regulated entities only, NGT broadly supports Ofgem's current proposals of resilience requirements as they appear to reach that fair balance.

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 clear from SSMC what level of gearing Ofgem regards as "excessive", although we note that Moody's regard up to 75% as still being eligible for a Baa1 credit rating (considered a "comfortable" investment credit rating as discussed in FQ14). We would also note that clarification how any proposals would treat financing structures held at PLC level for organisations such as National Grid plc and SSE plc would be required should Ofgem pursue proposals that reference Midco/Holdco structures. However, NGT considers the proposals to be balanced and sufficient given the enhanced visibility and longer-term assessments such new requirements provide, particularly once combined with the existing structure of price controls and the deliverables inherent within them and incentives therefore provided to network companies to fulfil their obligations or lose allowances/funding.

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?

Financing and dividend policies depend on multiple factors and are inherently complex. Imposing restrictions that reflect a limited set of those factors may unduly restrict the flow of financing transactions and undermine Ofgem's principle of allowing network firms to implement their own financing structures within the appropriate regulatory guidelines. Such restrictions may also undermine investors' confidence in investing in the sector and unduly increase costs to the consumer.

NGT's dividend policy references a number of factors but key determinates of the levels of dividends paid are existing resilience measures (i.e. gearing and the subsequent impact of the tax clawback mechanism if gearing levels are exceeded), the investment of requirements of NGT as a whole (taking into account all businesses, not just natural gas), performance of the various business units within NGT (including unlicenced activities) and ensuring it has sufficient facilities available to fulfil its licence obligations (i.e. balancing, shrinkage purchases etc). External borrowing arrangements and covenants are aligned to these requirements.

The proposed policies should be sufficient for Ofgem to understand how policies are derived, how they reference resilience requirements already in place and judge whether they are sufficient without placing undue restrictions on network companies and interfering with the key principle that network companies have the choice to implement own financing structures. We also note that existing RFPR reporting requires networks to report the source of funds for dividend payments.

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?

The risks of the retail sector are significantly different and as Ofgem point out, resilience measures have generally been effective, as demonstrated by absence of network firm failures or significant distress as seen in other industries/sectors. This has been the case despite significant pressures on network firms (in NGT's case, significantly higher than forecast shrinkage costs and a delay in recovery of those allowances) within the RIIO-2 period and reflects well on the approach taken.

Furthermore, a responsible network company should perform a rigorous analysis of its own forecasts to facilitate senior sign off of the Availability of Resources reporting that already exists. This should and does consider the assessment of suitable downside scenarios. Additionally, forecasts will be critically assessed by credit rating agencies to support the issuance of investment grade credit ratings. As such, NGT does not consider additional stress testing to be necessary.

If such a policy was to be implemented, the design of stress test scenarios would need to be carefully designed to ensure they were suitable and appropriate to NGT's role on the network.

Corporation tax

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

We do not have any strong objections to Ofgem's proposal to maintain the RIIO-2 approach to the calculation of tax allowances.

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

In principle the amendment to the tax clawback calculation to include accretion on inflation linked derivatives within the definition of net debt (the only amendment to the tax trigger calculation proposed by Ofgem) appears reasonable as it aligns with network firms obtaining tax relief for or being taxed on any credits arising in respect of, derivative accretion movements. The tax clawback aims to reduce the tax allowance where actual gearing/ interest costs afford the business a higher level of tax relief than that provided through the notional gearing concept within the tax allowance calculation. It is therefore important that the actual gearing/ interest in the tax clawback calculation are accurate and it would appear that including inflation linked derivative accretion helps to achieve this.

The proposal to take into account derivatives in the assessment of gearing when such instruments are excluded from the calculation of cost of debt allowances will result in an inconsistency between these proposals if enacted. This is discussed further in our response to FQ1.

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?

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?

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

FQ21, FQ22 and FQ23 combined.

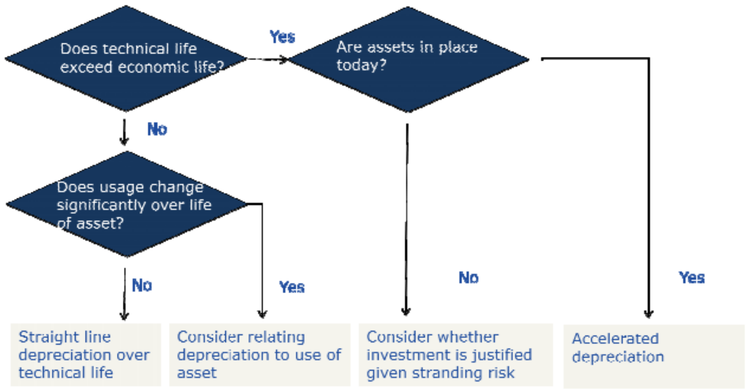
We support the assertion that it is appropriate to address the asset stranding risk under the RIIO principles given the need to match economic lives to asset usage by the relevant population of consumers and the potential for negative investor perception of the sector if it is not. However, given the presence of related matters such as the costs of decommissioning and uncertainties around the implementation of future technologies, NGT does not agree that the risk raised by future of gas scenarios are fully addressed and therefore are not factors to be considered when assessing WACC. This will be addressed relevant responses, notably around the methodology to assess forward-looking risk in WACC.

NGT also recognises and supports the assertion that the starting point for setting asset lives should be the economic life of assets to align recovery of allowances with the value provided to consumers. This assessment should take into account changes in the technical/economic life and therefore adjusting asset lives is also recognised as an effective tool for addressing any remaining stranding risk inherent in the move to new technologies. Any adjustment to asset lives to address stranding risk also needs to consider the balance of being fair to categories of network users (i.e. natural gas, hydrogen and carbon) as well as investors.

Regulatory depreciation of the RAV does not correspond to a physical asset base but rather to the network's unrecovered financial investment and retained performance. However, whilst not directly linked to physical assets, the technical and economic lives of the current asset base provide a useful reference against which to review the regulatory depreciation profile. In RIIO-2 the procedure to establish asset lives was as detailed below:

- Understand future demand scenarios to inform potential economic life of the physical assets
- Review the technical and accounting asset lives and depreciation profiles of the current asset base

- Reference to the methodology as set out by CEPA et al.[64] (and reproduced below) prior to the implementation of RIIO-1 as an initial tool to identify alternative regulatory depreciation profiles of the RAV.



The range of potential natural gas annual and peak demand shown by forecasts and the range of outcomes possible given the maturity of hydrogen and CCS business models at this stage make it difficult to categorically conclude on an appropriate asset life at SSMC.

Ignoring the opportunity to repurpose assets and transfer them to the RAV of a future business (i.e. hydrogen/CCS) at this stage and assuming high level projections of asset health spend to 2050, we have modelled the value of RAV remaining and 2050 and 2070 for both the existing 45 year life and a 35 year life as an alternative. The results of this modelling are summarised below:

	RAV at end of FY23 £bn	Forecast RAV at 2050 £bn (% of FY23 RAV)	Forecast RAV at 2070 £bn (% of FY23 RAV)
45 year life	7.1	5.8 (81%)	4.4 (61%)
35 year life (back dated)	7.1	4.5 (64%)	3.6 (51%)
35 year life (from RIIO-3)	7.1	4.9 (69%)	3.6 (51%)

Note all scenarios retain a Sum of Digits depreciation methodology, which NGT continues to support given the better alignment of allowance recovery profile and number of natural gas users than the alternative Straight Line methodology offers.

[64] The Economic Lives of Energy Network Assets – A Report for Ofgem, Cambridge Economic Policy Associates Ltd, Sinclair Knight Merz, GL Noble Denton, Section 2.2.3, page 7, Fig 2.1

In all scenarios, the majority of the RAV balance remaining at 2050 and 2070 consists of investment made after the RIIO-3 period, which can and will be re-assessed at each price control period, as indeed would asset lives. For example, in the 45 year life scenario, of the £5.8bn remaining at 2050, we estimate that £5.3bn consists of post-RIIO-3 investment. The same value for the 35 year life scenarios is £4.4bn.

However, it is important to consider that existing natural gas assets can and should be repurposed to support the adoption of new technologies that drive the transition to Net Zero. If an appropriate mechanism to identify, value and transfer natural gas assets to a hydrogen/CCS business can be established, this will help mitigate the stranding risk for a significant portion of the existing natural gas RAV, avoiding decommissioning costs in the process, as well as providing benefits to the users of new technologies given that current research suggests the cost of repurposing existing assets is significantly lower than constructing new assets[65] and lead times are likely to be shorter.

NGT has been working with Frontier Economics to assess how such asset transfer and valuation mechanisms could be established and the options available to Ofgem and NGT. The matter is complicated by the manner in which RAV is constructed in UK regulated entities, in that it represents an amount of allowances to be recovered over future periods, rather than being akin to a register of individual assets. This means that any methodology to establish a fair value of the assets being transferred between the natural gas RAV and a hydrogen or CCS RAV needs to make assumptions on the best and fairest way of assigning a value to the asset being transferred. A variety of methodologies have been assessed and presented to DESNZ and Ofgem at a principles-level but further work is required to establish a favoured option. This is an important judgement as establishing a practical methodology that finds the most appropriate balance of fairness between current natural gas customers and future hydrogen or CCS customers is crucial in facilitating the Net Zero transition, albeit we believe that transferring assets within the same regulated entity makes the process significantly less complex.

Key principles being employed to establish this mechanism have already been presented to DESNZ and Ofgem and discussions will continue, but in summary any mechanism needs to address the following considerations to unlock timely repurposing:

- A framework is needed to unlock the benefits of repurposing given the development of a distinct business model for hydrogen/CCS and to ensure efficiency (rather than assessing the value of each individual asset at each transfer event)
- RAV should be conserved to prevent customers under or over-paying for assets
- A reasonable estimate of RAV must be derived – a range of options are available (as summarised below) but a key consideration is avoiding distortion of the remaining natural gas RAV

[65] The European Hydrogen Backbone work: https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf (Table 1, page 17)

- Investors may place a different value on an asset to its RAV – RAV should be conserved under any methodology being considered but any premium generated may serve to further mitigate decommissioning costs to remaining natural gas customers

Several methods of estimating the value of assets held in the RAV are being considered, which have varying degrees of feasibility an accuracy:

"Bottom up" approaches:

- Historic cost – potentially difficult to extract/estimate given construct of the RAV and likely to overestimate value of asset
- Replacement cost, such as Modern Equivalent Asset Value – unlikely to align with the RAV of the wider network and therefore likely to overestimate value of asset

"Top down" approaches:

- Simple disaggregation, for example:
    - average RAV/km
    - using bottom up approach i.e. historic cost/MEAV
    - based on outputs i.e. charges, volumes

No one approach is wholly accurate or feasible and therefore a combination may be required to calibrate values but in all cases, transferring assets within the same entity is likely to be more straight forward than an external transfer.

In parallel with the development of the natural gas-only RIIO-3 business plan, NGT is developing detailed plans for the hydrogen backbone project, known as Project Union. Project Union ultimately facilitates the construction of c.2500 km of hydrogen transmission pipelines and provides hydrogen connections to power stations and heavy industrial users crucial to maintaining energy supplies and the UK industrial base in a Net Zero environment. Each proposed leg of Project Union has its own mix of new and repurposed assets, that mix depending on the assets already in place in each geographical location and the resilience requirements of that area. The main element of Project Union work is likely to be carried out in accordance with DESNZ's Hydrogen Transportation Business Model and the proposed investment allocation methodology. The proposed timetable for assessing projects means that applications will be made by the end of 2024 and therefore clarity on the extent of Project Union investment and therefore the extent of repurposing is unlikely to be confirmed until well into 2025. Therefore, using the simplified assumptions akin to a top-down assessment of the value of RAV (i.e. £/km), we have modelled two illustrative scenarios for the proportion of repurposed assets in the Project Union plan against the existing RAV. Note whilst not directly referenced the proportion would logically increase should CCS be included in the analysis.

Taking this analysis into account, under either scenario the proportion of natural gas RAV at risk of stranding is significantly reduced:

	FY23 RAV £bn	**30% re-purposed**	
		Forecast RAV at 2050 £bn (% of RIIO-3 RAV)	**Forecast RAV at 2070 £bn (% of RIIO-3 RAV)**
45 year life	7.1	4.0 (57%)	3.1 (43%)
35 year life (back dated)	7.1	3.2 (45%)	2.5 (36%)
35 year life (from RIIO-3)	7.1	3.4 (48%)	2.5 (36%)

		60% re-purposed	
		Forecast RAV at 2050 £bn (% of RIIO-3 RAV)	**Forecast RAV at 2070 £bn (% of RIIO-3 RAV)**
45 year life	7.1	2.3 (33%)	1.7 (25%)
35 year life (back dated)	7.1	1.8 (26%)	1.4 (20%)
35 year life (from RIIO-3)	7.1	2.0 (28%)	1.4 (20%)

As with scenarios without repurposing, a significant proportion of RAV remaining at 2050 is driven by investment made after the RIIO-3 period:

- 45 year life: £0.4bn relates to investment up to RIIO-3 (30% re-purposed), £0.2bn (60%)
- 35 year life (back dated): £0.1bn (30%), £0bn (60%)
- 35 year life (from RIIO-3): £0.4bn (30%), £0.2bn (60%)

We strongly emphasise that the inputs to this modelling will continue to mature as hydrogen business models and plans for Project Union evolve and the scenarios above are provided for illustrative purposes at this stage and are therefore not a proposal of what assets lives should be set to for RIIO-3. We therefore do not recommend that a final conclusion on the RIIO-3 asset life for GT is established at SSMD.

NGT would welcome the opportunity to continue to work with Ofgem to share our approach to modelling this matter and to refine the RAV transfer methodologies being considered and the subsequent impact on asset lives. NGT believes the best outcome at this stage is to ensure that an agreed methodology for valuing and then transferring assets between RAVs is agreed and in place for the beginning of the RIIO-3 period. This would ensure that both NGT and Ofgem has a clear understanding of how such transfers will be facilitated by the start of RIIO-3 and so that they can be transacted as efficiently as possible at the appropriate time.

NGT does however recognise that any conclusion on the impact on asset lives for the RIIO-3 period is inherently dependent on the proportion of the existing natural gas RAV expected to be transferred to new businesses, which may not be clear during the business planning process for RIIO-3. We also recognise that delaying such a decision delays the partial mitigation of the risks associated with the gas transition to Net Zero via action on asset lives. As such, NGT and Ofgem may need to use judgement based on analysis of the information available at the time or indeed consider other factors, such as the financeability outcomes, to arrive at “least regret” parameters for the RIIO-3 period. We re-emphasise that whilst such action may be necessary, the inputs utilised in setting an appropriate cost of equity and cost of debt should be rigorously assessed before resorting to alternative adjustments that simply change the phasing of allowances.

If the uncertainty around assessing key inputs is too great before a commitment must be made in the RIIO-3 process, it may be appropriate to maintain existing asset life parameters and delay a decision until the finalisation of hydrogen/CCS business models and further work has been performed on Project Union plans, which may be after the start of the RIIO-3 period. Such a decision could therefore be reserved for a re-opener mechanism during RIIO-3. However, any change to asset lives would impact any assessment of the financial package “in the round” and potentially lead to a different conclusion and require additional action. It may therefore be more appropriate to restrict the scope of any such re-opener to a change in asset lives only and not include a wider re-assessment of financing parameters at that stage.

Using the modelling parameters noted above, delaying the asset life decision would result in c.£200m of depreciation allowances not being recovered during the RIIO-3 period (using 45 years and 35 years as the two scenarios). In addition, if the economic life is backdated, as is assumed in our scenarios above, the impact would be an “under-recovered” amount of depreciation allowances totalling c.£650m by the beginning of the RIIO-2 period. If this is recovered over the period to 2050 this would result in a further £135m under-recovery during the RIIO-3 period. We again emphasise that this is a simplified view based on the information currently available but does illustrate the amounts that would need to be caught up in future regulatory periods should the decision be delayed until RIIO-4 (or equivalent).

We are committed to continuing our engagement with DESNZ and Ofgem on these matters that are crucial to the enablement of an efficient transition to Net Zero, with the aim of arriving at the best possible outcome for all parties at the earliest point. In summary, NGT believes at SSMC it is appropriate to:

- Leave the decision on asset lives open at SSMD and commit to re-assessing the evidence available at key points in the price control process;
- Acknowledge the need to establish principles on which a fair asset transfer methodology can be based, which will require further work and dialogue between NGT and Ofgem

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?

See also response to question FQ21. NGT would welcome Ofgem's view on the proposed methodologies for valuing and transferring assets between RAVs, particularly given the timetable for DESNZ's Hydrogen Transportation Business Model applications during 2024. We would also welcome confirmation that asset lives will continue to reference the best available evidence on technical or economic lives at the point of SSMD.

We recognise that at later stages of the build and approval of the NGT's business plan that further discussions will be necessary to conclude on this matter, particularly as discussions on future business models evolve and new evidence on the subsequent impact on natural gas assets results from those discussions.

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.

NGT has not submitted a response to this question.

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?

The acceleration of cashflows has the same short-term impact as shortening of assets lives. However, it would not appear to address the need to ensure the remaining natural gas RAV is fully recovered by the appropriate de-energisation point.

Furthermore, we note that as laid out in our response to question FQ3, the combination of granting a "semi-nominal" cost of debt and setting the weighting of index-linked debt in the notional company is not supported by NGT.

Return Adjustment Mechanisms

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

RAMs are in place to provide protection to consumers and investors from network company performance that is significantly higher or lower than anticipated when setting each price control. RAMs currently apply to operational performance only (that is they exclude financing and tax performance) and are applicable to performance of 300 bps over or below the allowed return. Operational performance reflects the uncertainty inherent in setting allowances and calibrating incentives, particularly where there is a range of outcomes possible in future demand scenarios or economic uncertainty. RAMs therefore protect against outturn scenarios that differ materially from expectations when setting the price control, although the price control itself should be well-calibrated by Ofgem based on a reasonable assessment of the information available at the time.

On the other hand, financing performance reflects the principle of network choice in implementing financing structures (as summarised elsewhere in our response) and therefore any resulting performance vs allowances reflects those choices made at the investors' risk.

As such, we agree with Ofgem's assertion that there is not a strong case for adjusting the RAMs methodology. Thresholds should be calibrated to provide an appropriate balance of incentive to outperform against allowances (which ultimately benefits consumers through the Totex Incentive Mechanism) and should be assessed in the context of network performance in the existing price control period. Based on the latest set of RFPR reporting there appears limited evidence of network companies approaching excluding cap and collars and therefore there appears limited evidence to change thresholds at this stage.

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?

See response to FQ27.

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?

We do not consider there to be evidence that suggests such an approach would be relevant to NGT.

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)?

NGT does not consider there to be a strong case for amending the current approach (i.e. starting with the natural capitalisation rate for Totex plans) given the simplicity of this approach and the inherent fairness to investors and consumers that it brings (that is the matching of the timing or allowance and expenditure or the period over which value is provided to network users). NGT does not consider there to be a need to expand the bucketing approach to each individual uncertainty mechanism application given the additional complexity this would bring to setting allowances, revenue calculation and reporting. We also note that forecast capex in the latest PCFM is broadly aligned to RIIO-2 capitalisation rates, being c.66% for baseline (65% capitalisation rate) and 83% for Uncertainty Mechanisms (75% capitalisation rate).

Regarding financeability, we remain strongly of the view that the allowed return granted to NGT should be sufficient to fund the agreed investment plan and the risk conditions NGT operates under. Any moves away from the natural capitalisation rate should be limited to marginal changes, otherwise the impact of bringing cash forwards is unlikely to be sustainable in the long term and will create intergenerational mismatches in consumer bills.

If relevant, marginal changes can be affected through a split capitalisation rate across baseline and UM allowances, as was the case in RIIO-2.

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?

RIIO has up to this point operated as a Totex price control, the principle being that there should be no incentive for a network to favour an opex or capex solution, rather the most efficient solution to delivering an agreed deliverable. Introducing a revised Totex Incentive Mechanism (TIM) that reacts to outturn may create the unintended consequence of an incentive for networks to implement a particular option based on the TIM outcome (i.e. balance of fast/slow allowances) rather than the most efficient solution.

Furthermore, such a mechanism may prove complex to implement as parameters for assessing TIM and subsequent fast/slow allowances may change annually, a knock on effect of which would be volatility and unpredictability in allowances and consumer bills.

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

NGT activities in this area are not expected to change materially in the RIIO-3 period and as such, we see no reason as to why there needs to be a different approach for RIIO-3.

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

Currently NGT does not have any requirement for more directly remunerated service categories.

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?

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?

FQ34 and FY35: a distinction should be made between asset disposals in line with existing activities (i.e. disposal of assets that have been decommissioned) and asset disposals by the natural gas business that are more akin to transfers to other business models i.e. CCS and hydrogen. For the former category, NGT sees no significant drivers for changing the RIIO-2 approach to the former as existing customers should benefit from assets that are likely to have reached the end of their economic life and therefore have been paid for by natural gas customers. As such, it appears appropriate to return proceeds to consumers as quickly as possible for reasons of inter-generational fairness.

Regarding asset transfers to other business models, as separately presented to Ofgem and DESNZ and summarised in FQ21, NGT is of the view that a mechanism should be established to appropriately value and transfer relevant assets to be repurposed to RAVs of the other businesses (CCS or hydrogen). Repurposing natural gas assets for hydrogen or CCS purposes delivers benefits to multiple parties, notably reducing the cost of implementing new technologies vs new build (subsequently reducing the need for subsidy) and helping mitigate lifecycle risks to natural gas customers.

In respect of RFPR or other reporting on asset transfers, given the RAV is not akin to an asset register, a methodology will need to be agreed that applies an appropriate value to each asset transferred. Any related reporting will therefore need to cover as a minimum information that provides Ofgem technical data that clearly demonstrates which physical assets have been transferred and related operational detail, but also a clear demonstration of how the agreed valuation methodology has been applied to each asset.

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?

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

FQ36 and FQ37: As noted in the SSMC, the existing requirements for reporting executive pay are akin to the Company Law/Listing Rules requirements for UK-listed plc's. As such they already go beyond the requirements applicable to NGT in its statutory reporting. We acknowledge that the manner in which network companies approached RFPR may have varied but consider that Ofgem should utilise existing powers to ensure consistency with existing requirements.

NGT recognises the need to continuously assess governance and reporting requirements around financial resilience and dividend polices and has responded to relevant questions in that section of SSMC accordingly.

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?

The price control financial model (PCFM) is used to calculate the Allowed Revenue during a given price control period. The PCFM has evolved over price controls with the fundamental requirement is that it reflects the Licence conditions that are in place.

NGT is already contributing to the development RIIO-3 PCFM through the associated workshops which have been arranged by Ofgem. NGT will continue to support this working group and would welcome additional engagement with Ofgem to further support and develop the PCFM for the RIIO-T3 period.

The exact structure and format of the PCFM can only be completed once the RIIO-T3 framework is determined and must be consistent with the licence terms and structure. However, there are specific issues identified in the RIIO-T2 which we consider should be resolved in the RIIO-T3 PCFM. Firstly, there has been significant change in the corporation tax regime during RIIO-T2 with the introduction of accelerated capital allowances being reported to Ofgem in an offline model outside of the PCFM through the tax trigger process. The RIIO-T3 PCFM should be updated to reflect the tax legislation in place at the time.

There is also the opportunity to extend the PCFM for use in years beyond the price control period to enable more efficient calculation of price control close out processes within a single PCFM.

NGT also notes that there is some discrepancy between the price base required to report certain cost elements within the Regulatory Reporting Process (RRP) and the price base of these inputs in the PCFM. This creates complexity of process and could be simplified by achieving consistency of price base across the RRP and the PCFM.

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?

NGT is keen to explore the PCFM self-publication approach with Ofgem further. We see this as a potential opportunity to reduce the lead time between publication of the Allowed Revenue within PCFM and the start of the charging period.

NGT revenue recovery commences on 1 October each year, when the gas charging year commences, for a given price control year. The PCFM, which sets the Allowed Revenue to be collected via charges, is typically published in January, approximately 8 months earlier. For example, a PCFM published in January 2024 calculating the Allowed Revenue for the year ended 31 March 2025 is used to set charges with collection commencing on 1 October 2024. Under the current licence, NGT has the ability to request a republication of the PCFM up until the end of May each year. However, such a republication is only permitted should there be a material change in assumptions, set at 10% of Allowed Revenue for each of the TO and SO. Irrespective of any republication in May, there remains a long lead time from republication of Allowed Revenue to setting charges. During this lead time, it is possible for components of Allowed Revenue to change significantly for the year in question, as was the case with shrinkage costs in FY23. Pricing for the gas year commencing 1 October 2022 was based on a forecast of £286m, included in the republished PCFM in February 2022. Ultimately shrinkage costs for FY23 totalled £628m, driven by gas prices and significantly higher than forecast volumes of gas transported to mainland Europe. These factors were known before publication of SO prices in early July 2022 and as such could have been more accurately reflected on prices should a later republication have been permitted by the licence.

Both NGT and network users would benefit from the PCFM reflecting the best available information prior to the before the start of the charge setting process and self-publication may be a route to achieving this.

However, consideration of the mechanism and governance approach must be further explored to ensure a robust process is developed.

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?

In RIIO-2, under- or over-recoveries driven by volume or pricing (“Kt”) are adjusted using SONIA (Sterling Overnight Indexed Average) to reflect the time value of money. Other under- or over-recoveries captured in the “ADJ” term are instead adjusted using a network’s WACC. Network firms and in particular NGT (given exposure to costs associated with its role on the network i.e. shrinkage) are exposed to timing differences given the number of variables present when setting prices to recover Allowed Revenue, some of which have seen extreme volatility in recent years (notably volumes and gas prices resulting in significant under- and over-recoveries for Allowed Revenue and passthrough costs).

WACC is considered a suitable indictor of the financing position of a network and the costs of financing under-recoveries. Given the principle of network choice of financing strategy it does not appear appropriate to utilise WACC to adjust for the time value of money for all timing differences.