5. NATIONAL GRID GAS TRANSMISSION RESPONSE TO RIIO-2 DRAFT DETERMINATION: NGGT ANNEX

Contents

Introduction

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

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

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

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

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

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

Structure of this response

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

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

For ease of reference, we have included all of key concerns on the RIIO-2 Draft Determination for NGGT in this document.

We provide more detail on our key concerns across the three topic areas of **introducing significant risk to the reliability and resilience of the network; unnecessary complexity and volatility introduced in the framework;** and **eroding regulator stability and investor confidence**.

This document covers material relevant to Ofgem's NGGT annex, but also covers wider topics in the suite of Draft Determination documents, where relevant to the RIIO-2 proposals for NGGT. The concerns we set out here should be read in conjunction with the question responses and detailed evidence provided (i.e. documents 3-7 of our response).

NGGT response to RIIO-2 Draft Determination: NGGT Annex

This document is structured as follows:

The rest of this document includes our detailed response to the specific questions raised in the Ofgem **NGGT DD annex**. The detailed responses on other topics can be found in documents 3-4 and 6-7 of our response.

Summary

Below we summarise our business plan submission, Draft Determination and response baseline figures.

Ofgem's breakdown of our business plan in the Draft Determination, showed a proposed baseline of £2602m including £58m of efficiency. This does not fully reflect our business plan submission from December 2019, which proposed a baseline of £2,602m, including £92m of efficiency.

Ofgem's Draft Determination proposed a total baseline totex of £1,559m however, following conversations with Ofgem it was confirmed that this view was overstated by £32m [redacted]. NGGTs view of the corrected Ofgem Draft Determination baseline is £1527m, a reduction of £1,075m form our business plan submission.

We have analysed the Draft Determination and engaged with Ofgem to understand the detail behind Ofgem's proposals. As part of this we have identified a number of errors and these have been shared with Ofgem during the consultation period and therefore need to be addressed for Final Determinations. We have provided an error log (NGGT Annex Errors and Issues log) that details the issues and have highlighted specific errors throughout our responses.

Following our analysis of the Draft Determination, we propose our baseline allowance to be £2,283m including efficiency of £62m. More detail breakdowns on individual spend categories can be found within this document from question NGGTQ20 onwards. Further details on the efficiency calculation alongside reconciliations for the submission and Draft Determination figures can be found in NGGT Annex Allowances reconciliation.

Table NGGT1 – summary of DD response

Cost Category	Per DD NGGT Proposed	NGGT view NGGT Proposed	Per DD Ofgem Proposed	NGGT view Ofgem Proposed DD	NGGT view NGGT Response
Load related expenditure	11.59	11.59	2.44	2.44	11.59
Non-Load related	898.74	898.74	517.51	517.51	794.65
Other costs	545.80	552.47	230.31	198.24	358.63
Non-Op Capex	296.50	296.50	68.40	68.40	245.95
Network Operating costs	389.51	390.42	379.65	379.66	390.42
Indirect costs	518.24	544.40	411.10	411.10	544.40
Efficiency	- 57.92	- 91.67	- 50.50	- 50.50	- 62.22
Total	**2,602.45**	**2,602.45**	**1,558.91**	**1,526.85**	**2,283.43**

1. *In the submitted plan efficiency was applied to the following areas; Capex: Non-Load & Cyber OT and Opex: Operating costs, Indirect costs and Physical Security.*
2. *Ofgem's submission figure for efficiency did not pull out all embedded efficiencies in the submitted plan. Therefore, the DD calculation of efficiency double counts some efficiency.*
3. *Efficiency is applied to ex-ante baseline only.*
4. *The efficiency in DD was applied to all areas apart from Cyber OT (which is UIOLI). Our response sets out why we don't agree with this approach.*
5. *The response efficiency has been applied to areas as per submission efficiency, allowing for Ofgem unit cost efficiency applied in some areas.*

The proposed baseline allowance includes £382m of costs that will be subject to ex-post reopener adjustments or UIOLI mechanisms making our ex-ante baseline (not subject to UMs) allowance of £1901m. This assumes Ofgem accept all our evidence-based proposals set out in our response, such as our alternative NARMs performance mechanism covering £309m of allowances and ex-ante funding for pre-construction works on our compressor and major projects.

Consumer research

We continue to believe that our proposals are aligned with the needs of stakeholders. In order to ensure this is the case, in the changing external environment, we have continued to undertake consumer research as we have developed our response.

Since the 9 July 2020 and during the COVID-19 pandemic, we instructed Populus[1] to undertake a nationally representative survey of 4,018 members of the public to obtain views on; the importance of investment or cutting costs with regards to potential priorities in the energy sector; which investment/cost-saving priorities are most important; and the level of support or opposition for changes in energy bills to support investment priorities.

The results show that the ***public favours investment over cutting spending*** in every instance. They are particularly ***supportive of investing in green energy and improving network resilience, and fully aligns to our business plan proposals.***

Please see NGGT Annex Populus consumer research for more information.

[1] Populus is a founding member of the British Polling Council and abides by its rules. www.populus.co.uk

Introducing significant risk to the reliability and resilience of our network

1.1 Asset health – volume reductions

We are concerned with the proposed asset health volume reductions and the design of the associated ex-post adjustment mechanisms being applied to the NGGT business plan. We believe this introduces significant risk to the reliability and resilience of the gas transmission network. We have responded to the Ofgem questions (Chapter 3 of NGGT Annex Q25 to Q28) detailing specific challenges to both proposed cost and volume reductions to our plan. In this part of our response, we summarise the principle concerns relating to volume adjustments and identify the remedies we require in Final Determinations.

Our stakeholders have consistently told us reliability is a top priority for them and one that they are willing to pay for. For our business plan they told us they wanted us to maintain the absolute level of risk on the network over the next ten years. The Draft Determination will not allow us to do this.

The allowances of £390m for asset health detailed in the DD are (10%) lower compared to what we have been spending in RIIO-1 (£435m[2]) and are (37%) lower than our business plan (£616m). This level of funding is not adequate when considering the increasing workload required to address age and deterioration related asset health issues, as a result of which we invested over £62.5m above our allowances to maintain risk on the network in RIIO1.

Spending in-line with Ofgem's DD allowances will result in the absolute level of risk on the network increasing by 7% over the next ten years, and the long-term risk on the network will worsen by 19%. It is particularly concerning that the asset health allowances in the DD only allows us to deliver 83% of our legislative requirements. We recognise that there are some uncertainty mechanisms relevant to this area of spend. However, even if all the uncertainty mechanisms proposed are subsequently approved, the long-term risk on the network will still worsen by 14%.

The consequence of increased risk on the network can lead to constraints and limit the ability of our customers to bring gas on and off the network where and when they want. We know that increased constraints have a direct wholesale market impact for consumers with these costs being significantly above the cost to maintain the reliability of the network and is an unnecessary risk to pass on to consumers.

The proposals are in direct contradiction to what our stakeholders told us they wanted, which was to maintain the level of risk on our network over the next ten years. Ofgem has failed to consider the consumer consequences of its asset health funding proposals. It has not explained how we are expected to maintain the availability and reliability of our network for consumers, while also spending in-line with its allowances. Overall, Ofgem appears to have ignored the results of our stakeholder engagement, and we urge it to correct for this fundamental failing.

The above is a conservative assessment of the impact the DD allowance will have on risk. This is based only on assets covered by the NARMs methodology. However, the risk impact will be greater if non-lead assets and major projects remain underfunded.

It is vital that Ofgem's Final Determination provides the asset health allowance needed to fulfil our legislative and licence obligations. This can be achieved by adding £115.05m with the associated output commitments to our baseline allowance. We provide evidence within our detailed response of the consequences of the DD and what is needed to meet our licence obligations, addressing the topic further in our response to NGGT annex questions 25-28 (inclusive).

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[2] Based on an equivalent 5-year period.

Material concerns with Ofgem approach to volume adjustments
As outlined in our business plan we developed a number of programme options that had been fully costed and the impacts determined. We have also undertaken a full CBA for each option with the benefits of each option based on our NARMs methodology[3].

We set out the concerns against assets that contribute to NARMs output and the volume reductions for non-lead assets and the proposed remedies.

<u>NARMs related asset health volumes</u>
Ofgem propose a reduction in volumes related to our pipelines and compressors asset themes that both contribute to maintain long term risk of the network. Ofgem's assessment is based on a bottom up approach and does not take full account of expected and future degradation that would occur on our assets and this is a flaw in Ofgem's methodology.

On the compressor asset theme, we acknowledge, since our plan submission the forecast running hours have fallen. Based on new forecast running hour projections we are not currently expecting a need to undertake overhauls covering £20m of our proposed investment. Notwithstanding asset health volumes which we accept the need to move into uncertainty mechanisms, for the remaining elements, we propose that where we have justified unit costs for these works, volumes are increased to contribute to maintaining stable long-term risk on the network. Since DD, we have provided additional evidence that supports our proposals.

For plant & equipment, which represents £156m (25%) of our asset health plan, we acknowledge that this requires an uncertainty mechanism to ensure a balance of risk between consumers and NGGT. To ensure we are able to maintain risk on the network we propose that the reopener specifies a minimum long-term risk benefit level that will be assessed during the reopener. The reopener then focuses on the scope and unit cost of the work rather than undertaking a further unnecessary assessment of the level of risk that we should achieve. This approach avoids passing additional risk onto consumers during RIIO-2 where NGGT is best placed to manage.

Remedies needed:
- Increase NARMs related volumes associated with pipelines and compressors in-line with our additional evidence provided in this DD response.
- For Plant & Equipment, agree the long-term risk benefit level that will be assessed during the reopener.

<u>Non-lead asset health volumes</u>
For Compressor Cabs, we do not agree with the proposed design of the reopener mechanism that would require an ex post review of our costs. We propose and have provided additional evidence to allow Ofgem to set ex ante allowance for the pre-construction / development works required to clarify scope and costs for additional works that will be required in RIIO-2.

For Civils, we do not agree with the volume reductions. As this is a high cost confidence asset theme, we propose a volume driver uncertainty mechanism for two specific assets[4].

Remedies needed:
- For compressors, provide ex ante funding for pre-construction / development works as set out in our DD response.
- For civils, introduce volume driver uncertainty mechanism as set out in our DD response.

[3] NGGT Business Plan – Optioneering section page 70.
4 Site Access Roads and Path Major Refurb (UID A22.18.2.4) and Security – Fences and Gates – AGI (Minor Works) (UID A22.18.2.11)

The table below summaries our DD proposals after the correction of errors in DD, additional evidence that proves needs case for workload volume and adjustments for the above remedies.

Asset Health Summary Table

Table NGGT2 – Asset health theme proposals and asset UM summary table

Theme	NGGT Proposed Plan (£m)	Ofgem DD Baseline (£m)	Ofgem DD UM (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Cabs	31.29	14.38	9.59	23.97	7.32	1.86	1.24	3.11	16.25	10.83	27.08
Civils	79.54	39.97	-	39.97	39.57	8.58	13.69	22.27	48.55	13.69	62.24
Compressor	113.69	69.51	-	69.51	44.17	18.76	-	18.76	88.27	-	88.27
Electrical	28.48	20.58	-	20.58	7.90	4.21	-	4.21	24.79	-	24.79
Pipelines	143.53	112.13	-	112.13	31.41	48.96	-	48.96	161.09	-	161.09
Plant & Equipment	156.44	82.28	54.86	137.14	19.30	9.83	6.56	16.39	92.12	61.41	153.53
Valves	63.15	50.83	-	50.83	12.32	22.84	-	22.84	73.67	-	73.67
Total	**616.11**	**389.68**	**64.44**	**454.13**	**161.98**	**115.05**	**21.49**	**136.54**	**504.73**	**85.93**	**590.66**

Theme	NGGT Proposed Baseline	Ofgem DD volume adjustment (£m)	NGGT volume proposal (£m)	Proposed UM and type
Plant and Equipment	156.45	100% as ex-post review proposed	Agreed upfront volume as described in our DD response	Cost & Scope Reopener
Civils	79.54	29.21	-	Volume Driver
Cabs	31.29	10.36	-	Reopener
Totals	**267.28**	**39.57**		

1.2 Non-operational Capex - IT and Telecoms - cost and volume reductions

We are deeply concerned with the proposed IT and Telecoms reductions being applied to the NGGT business plan. We believe this introduces significant risk to deliver both our digitalisation strategy and to deliver the required efficiencies we committed to deliver in our business plan. Our digitalisation strategy supports our contribution to the energy industry's whole system ambitions and is consistent with Energy Data Task Force recommendations. Leveraging digital has great potential to reduce costs for consumers. We have responded to the Ofgem question (Chapter 7 of the Core document Q18 and NGGTQ29) detailing specific challenges to both proposed cost and volume reductions to our plan and this summarises the principle issues and remedies need from DDs to Final Determinations.

Ofgem has proposed a reduction in our baseline funding for IT & telecoms of £216.7m from a submission of £251.6m. With £208.2m being proposed for uncertainty mechanism. This provides baseline funding for only six of 66 project lines. We do not agree with the assessment approach and the baseline allowances it has resulted in.

The assessment undertaken identifies the needs case for all assessed projects is acceptable and not the blocker to ex-ante funding. It also identifies that, of the assessed projects, cost certainty is a contributing factor to inclusion in UM for only three the 66. The main blocker to ex-ante funding is assessment of project maturity where it creates an unreasonable expectation of the maturity of investments, straying into areas of delivery risk that networks have always been expected to manage by shifting them instead to consumers.

We understand the assessment approach for IT costs was designed after the business plan submission in December 2019. Consistent with this there was no IT specific business plan guidance provided that identified additional areas of assessment beyond the general expectation set by the SSMD.

The assessment employed goes beyond the expectation set by the business plan assessment process as outlined in the RIIO-2 tools for cost assessment consultation published in summer 2019 and should be considered an error of policy.

For IT & telecoms investments the relevant primary workstream as stated in paragraph 5.6 of the RIIO-2 tools for cost assessment are (i) needs case assessment and (iii) cost assessment.

The Draft Determinations featured inconsistent treatment between National Grid Gas Transmission and Electricity Transmission for the same shared projects (i.e. those delivered jointly across our businesses to enable economies of scale). For example, all NGET indirect projects have been included in the totex baseline whilst the same projects in NGGT have been placed in the uncertainty mechanism. Low materiality projects that were fully funded for almost all other networks have also been included in the uncertainty mechanism in our Draft Determinations. We have highlighted and discussed these items with Ofgem and are confident these errors will be addressed for Final Determinations.

We can see the benefit of having a re-opener for certain very uncertain projects. However, we are deeply concerned that current broad scope will create a high burden on both Ofgem and networks, unnecessarily denies ex-ante funding for many like-for-like type investments and will be a further policy area that slows ambition in the digitalisation of the energy industry, the green recovery and UK's Net Zero ambition. To retain such a broad re-opener would fail in Ofgem's primary duty of protecting consumer interests.

If Ofgem does not move materially from its current position of baseline and UM funding, then given the potentially large numbers of projects to be developed ahead of the re-opener ex-ante allowances must be provided to support the development of capital projects as is the case for our other major investment projects.

Of the projects currently funded in baseline Ofgem have applied an efficiency reduction (circa 20% of allowed baseline) based on the rolling forward of this too broad assessment. There is no evidence (whether historic or based on industry best practice) to support the arbitrary levels of cost adjustments applied based on the outcome of a qualitative assessment approach. If retained, it will lead to a punitive allowance as low as 75% of the submission cost leaving us unable to deliver the requirements of the investment. Projects may need to be descoped resulting in more and potentially costly investment in the later part of the RIIO-2 period or RIIO-3 and beyond. In our response to NGGTQ29 we highlight research that demonstrate there is no basis for such upfront reductions.

We urge Ofgem to address errors of judgment leading to inconsistencies across multiple aspects of the IT & telecoms assessment approach. Correcting for the errors will ensure a strong foundation to agree a tenable allowance for our IT investments that will provide the certainty over the reliability and resilience of the systems we rely on, that our stakeholders need and allow us to play our part in the digitalisation of the energy industry, the green recovery and UK's Net Zero ambition.

Remedies needed:
In reaching Final Determinations Ofgem needs to adapt its cost assessment methodology to:

- be consistent with the expectation of a cost assessment set through the RIIO-2 tools for cost assessment consultation, focusing on need case and cost assessment;
- provide baseline allowance for projects with satisfactory need case and cost assessments, reducing the volume of projects subject to re-opener;
- address inconsistencies of assessment between networks;

- provide baseline funded projects with adequate allowances to deliver requirements, reducing the punitive maximum reduction of 25% to be commensurate with relevant experience and best practice.
- Increase the ex-ante baseline funding for projects subject to uncertainty mechanism in the period

1.3 Cyber resilience

As agreed with Ofgem, our response to DD for our cyber IT and OT resilience is covered in a separate confidential annex.

1.4 Blackrod resilience investment

We have serious concerns with Ofgem's proposal to reject the proposed Blackrod Reinforcement project. This is vital to provide additional resilience and security of supply to [redacted]. Ofgem has failed to recognise the considerable consequences of not undertaking this work in terms of the potential number of impacted consumers both domestic and commercial, the weeks (or even months) it would take to reconnect, associated costs and the risk to life as loss of supply is more likely to occur during a period of cold weather when demand is too high to be accommodated via the distribution network.

Based on comments in the consultation document, we are concerned that there is a misunderstanding over the need case for the proposed pipeline. The proposal was not made based on historic outages on the existing pipeline and whilst in favourable circumstances NGGT, working with Cadent, could accommodate planned or unplanned outages, there are circumstances where outages would impact supply to consumers.

With any pipeline there is an inherent risk of failure or other event that reduces its operational capability (e.g. a result of a safety requirement to reduce pressure following discovery of a defect or as a result of 3rd party damage). From this perspective, this pipeline is no more or less risky than other NTS pipelines of a similar age. The reason for our proposed investment at Blackrod was because during high demand it alone provides security of supply [redacted]

On the above basis alone, we would have proposed construction of the resilience pipeline.

We provided an EJP and CBA for this project which showed that the project remained cost beneficial even with a risk of pipeline failure of 1 in 2000 years and assuming a two-week period that consumers were not supplied with gas. This two-week period is extremely optimistic given the time it would take to reconnect a large number of consumers safely, and in the event of a catastrophic failure, the time a significant repair would require. We believe our analysis submitted with the business plan was proportionate and we had also been able to demonstrate the consumer value through a proposed CVP.

Ofgem have stated that we have not undertaken Quantitative Risk Analysis (QRA). Provision of a QRA was not part of the business plan guidance and its omission was not raised following publication of the draft versions of our business plans. A QRA was suggested for inclusion in response to one of the SQs however there would not have been sufficient time to complete this within 5 days and it was not highlighted as a mandatory requirement. This type of investment would not normally require a QRA as it passed an initial CBA which explained robustly the investment and benefits. The work was relatively low cost and the benefit to consumers were clear, we believe the information provided to Ofgem through the EJP, CBA and CVP, met the business plan guidance requirements and showed the consumer value of the proposed pipeline. However, to support Ofgem's assessment of the proposed investment, we are providing a QRA for Blackrod in this response. The QRA supports the case for the proposed pipeline investment.

Remedies needed: Provide baseline funding to facilitate Blackrod resilience investment for security of supply to [redacted] and the associated CVP reward.

Unnecessary volatility introduced in the framework

2.1 Uncertainty mechanisms

Within our business plan we proposed a robust package of uncertainty mechanisms to protect consumers from less certain costs or to ensure where needs change so to do our allowances. However, Ofgem has far extended the proposed use of uncertainty mechanisms. Ofgem have moved from our proportionate proposal of £650m to circa £1bn of UMs or 40% of our controllable costs in addition to the currently unquantified, more traditional UM approach for net-zero and quarry and loss. This will introduce a further level of regulatory burden, complexity and uncertainty on us and our stakeholders (including on the charges our customers and consumers will incur).

Delays in revenue through these mechanisms constrain our ability to deliver stakeholder needs as our metrics would deteriorate to almost sub-investment grade. The far-reaching use of uncertainty mechanisms adds to the complexity of the framework, leading to inefficiencies, delays and stifling innovation which goes against consumers interests. We have responded to the Ofgem questions (detailing specific challenges and this section summarises the principle issues and remedies needed in the Final Determinations.

Lack of framework clarity from Ofgem

It is vital that the process through which uncertainty mechanisms proceed is clearly established ahead of Final Determinations. The lack of full visibility of the licence conditions and associated reopener guidance against which any future submissions will be assessed is concerning and we expect Ofgem to fully consult on the guidance with stakeholders to ensure the impact on the industry and network companies price controls is fully understood ahead of Final Determinations. Our emissions reopener projects have legislative dates by when they need to be delivered and we need protection against regulatory delays in decision making.

Remedies needed:

- Clearly establish a route of appeal to the CMA in respect of Ofgem reopener decisions which have a significant and material impact on the overall price control package;
- Provide a commitment from Ofgem to decision making timescales to avoid project delay to avoid adversely impacting the efficiency of the reopener process, our planning and execution of work, utilisation of system access outages, contracting with the supply chain and complying with legislative requirements.
- Not provide Ofgem with the ability to trigger reopeners unilaterally at any point within the price control period.
- Provide ex ante allowances for pre-construction works based on our evidence of efficient costs

Further detail on this can be found in our responses to COREQ12, GTQ3 and NGGTQ24

Ex-ante development funding - major projects (compressor emissions, Bacton, Kings Lynn Subsidence)

Whilst these cover areas as proposed in our business plan and fit the process we have worked with Ofgem to develop, we are concerned about the funding mechanisms for these reopeners. Unnecessary ex post reviews of pre-construction activities will be intrusive, time consuming, add lengthy delays at a time when agility and flexibility is critical, and be resource intensive across network companies, Ofgem and our stakeholders. To be able to deliver at the pace required we require pre-construction works to be funded as ex-ante allowances. This is a proportionate approach to give certainty to make investment decisions across an entire portfolio of works with construction costs being assessed as adequate protection for customers and consumers. We have provided further evidence to support this in our responses to NGGTQ24 and NGGTQ27.

Remedy needed:
Provide ex ante allowances for pre-construction activities supported by the additional evidence submitted with our response.

Managing financeability and volatility caused by uncertainty mechanisms
Lack of ability to forecast outputs subject to uncertainty mechanisms results in unnecessary volatility in the charges our customers and consumers will incur. Without forecasting, our analysis suggests entry and exit charges increasing by around 40% (pre-inflation) in the final year of the price control. For many of the proposed reopener uncertainty mechanisms the needs case for the investment has been established. Uncertainty only exists in the precise scope or cost of activities. In these circumstances, volatility can be removed by aligning our baseline allowances with likely spend and adjusting from that position. This was proposed as part of our business plan and would remove many of the problems which the overuse of reopener uncertainty mechanisms has introduced. The mechanism has been deployed for Ofgem's approach to plant and equipment asset health spend. An alternative to this would be to allow forecasting of outputs.

Remedies needed:
- Provide baseline allowances for predicted construction costs with ex post true up during individual project reopeners; alternatively,
- Allow the application of forecasting of outputs for allowances subject to reopeners.

Please see our response to Finance Q12 and Q35 to understand the financial drivers and need to remedy this situation.

Asset health reopeners
Ofgem propose cab infrastructure and plant and equipment areas in the asset health UM, in addition we are proposing to include the Civils sub-theme (Security and Fencing, Access and Buildings).

For asset health reopeners, whilst we agree that asset health works undertaken in these areas should be subject to true-up at the reopener point, we believe ex-post reviews of pre-construction / development works to be unnecessary as set out for major projects reopeners above. We have provided further evidence to support an ex-ante allowance for pre-construction / development costs to allow Ofgem to justify this approach in our response to NGGTQ25.

We also propose an annual flexible reopener window to allow NGGT and Ofgem to agree suitable evidence requirements for each asset theme and allow the setting of ex ante allowances at the earliest opportunity in the price control. This is necessary as these mechanisms are new and Ofgem has not consulted on its guidance, which means we are unable to plan for a specific timeline at this stage.

Remedies needed:
- Provide ex ante allowances for pre-construction activities supported by the additional evidence submitted with our response.
- Agree a flexible annual reopener window during RIIO-2 for each element.

Further detail on these points can be found in NGGTQ37.

IT reopeners
We support the overall concept of this reopener but disagree with Ofgem's initial assessment of the costs to be included in this reopener.

We cover our proposals in our IT and Telecoms summary in this document and in response to COREQ18. As with other reopener uncertainty mechanisms, we argue that development costs related to reaching a required level of maturity should be ex-ante.

Net Zero reopener
We agree in principle with an additional mechanism to provide funding to enable critical new Net Zero outputs that are not otherwise catered for in the price control, for example a hydrogen network. However, we think the right mechanism is a project specific funding re-opener to fund new outputs that are required, for example, strategic projects that currently sit outside of the RIIO framework, but which may be required to deliver Net Zero. The critical Net Zero reopener can only be triggered by Ofgem and the scope of its potential use is not clearly defined. Ofgem has the ability to reopen the price control at any time, in the event of an unforeseen upside emerging, this creates a huge risk for companies who would be exposed in full to downside risk. We believe Ofgem need to better define this reopener and include a right to appeal new output requirements and funding decisions, given the potential high materiality. Further information can be found in COREQ23.

Cyber resilience (COREQ16), Physical Security (COREQ19), Quarry and loss (NGGTQ36), Pipeline diversions (NGGTQ35)
We broadly support the other reopeners set out in Ofgem's proposals, subject to the resolution of the broader framework points set out at the beginning of this section. However, we believe close out arrangements need to be considered these reopeners to ensure NGGT is held whole for relevant costs legitimately incurred in these areas. Please see the specific responses for further detail.

Pass through reopeners and indexation
We support the remaining pass-through and indexations proposed. We require further clarity on how Ofgem intend to allocate these costs across the Transmission Owner and System Operator. Our expectation is that the CDSP costs will form part of the System Operator revenues, the remainder being Transmission Owner related with both forms of control requiring a bad debt adjustment term

Eroding regulatory stability and investor confidence

3.1 Output delivery incentives

In network regulation, incentive schemes are recognised as powerful tools to create additional consumer value, aligning the overall costs and risks faced by the network company more closely with those faced by consumers. Well-designed incentives therefore play a fundamental role in the RIIO framework by financially incentivising network companies to make optimal decisions that can deliver significant consumer value. This can be achieved by designing the incentive scheme in a way that correlates a potential financial reward for network companies with consumer outcomes. The financial reward is typically linked to the network company outperforming an *ex ante* target. The incentive works by providing the network company with the flexibility to make optimal decisions to reach, or even outperform, that target.

We welcome that in some areas Ofgem has accepted NGGT's Business plan incentive proposals as, we continue to believe that for these schemes provide an appropriate risk/reward balance and create the incentive for NGGT to deliver additional value to customers and consumers. Specifically, we welcome the proposals on the following incentive schemes:

- Residual Balancing - as per our proposals.
- CSAT – as per our proposals.
- GHG – as per our proposals, importantly including an upside on GHG, which supports increase focus on environmental incentive.
- Decision to include a new Environmental ODI, using the basic design of NGGT's proposed environmental incentive.

However, on other incentives, whilst the proposals are aligned with Ofgem's position in the SSMD document, we feel there is no explanation of how these proposals are aligned with customer/consumer interest. The proposals do not appear aligned with the principle of strong incentivisation to encourage delivery of improved outputs for consumers, which was a cornerstone of the original RIIO framework. On these incentives Ofgem's focus appears to have been on reducing the value of the incentive schemes, either through reduced scheme parameters (caps, collars and sharing factors), not accepting proposals for incentive reopeners, by changing to a downside only schemes or by removing financial incentivisation completely.

We understand in circumstances where we have historically performed well against an incentive, and where the setting incentive parameters is complex, it is understandable that you may wish to take a conservative approach. One reason for this is because, even where consumers share in the gains from the network company's performance, the gains to the network company are more visible and tangible than the gains to the consumers. Or, put another way, significantly dampening an incentive provides a visible direct benefit to consumers (in terms of lower returns to the network company), but any losses to consumers (in terms of foregone efficiency gains) are less visible and difficult to quantify.

For some of these schemes there is little or no evidence available to justify the approach adopted or calibration of the proposed incentives. In some areas the proposals fail to recognise the effort and investment required by NGGT to maintain (if not improve) performance. In other areas we believe risks that we are best placed to manage are being transferred to consumers, who have no ability to control them.

The reduced strength of incentives will fail to deliver potential service improvements, leading to lost value to consumers. There has been little transparency over how this lost consumer value has been assessed against an apparent objective of making the schemes of lower value or weakened in incentive strength.

We have sought to actively engage with Ofgem via bilateral meetings to understand the basis upon which they have assessed our proposals and the analysis they have undertaken to inform the design of the ODIs proposed within Draft Determinations. Limited explanation has been offered beyond the cursory rationale outlined within their Draft Determination. Notwithstanding this, we have carefully considered Ofgem's proposals against the needs of our customers and stakeholders, our high-level views on these incentives is provided below:

- Demand Forecasting where the calibration of the scheme means that it is too small to warrant further investment to improve D-1 forecast accuracy. A more challenging/dynamic use of the network, alongside greater supply and demand volatility increases the challenges to accurate forecasting and investment levels just to stand still. We believe the outcome will be a focus on maintaining rather than seeking to improve forecast accuracy.

- Shrinkage where the move to a reputational only incentive means there will be a reduced focus on our activities, most notably in the price performance part of the scheme, which does not appear appropriate for a scheme with costs borne by consumers of £50-£90m/year nor is this consistent with the spirit of the RIIO framework.

- Maintenance where the move to a downside only scheme, removes any incentive to beat the scheme targets. This represents a risk of increased maintenance disruption to consumers which is inconsistent with the strong vocalised support for this incentive.

- Constraint Cost Management where the scheme for RIIO-2 has been simplistically designed against a perception of low probability / high consequence events and around RIIO-1 outcomes rather than the level of risk faced in RIIO-2. The Draft Determination scheme removes allowances necessary for us to undertake certain risk mitigation activities (for example, longer term constraint management contracts). We are concerned that this will impact the balance of system operation and asset investment and maintenance decision making processes, increasing likelihood of constraints faced and risks borne by customers.

It is not clear how the increased risks arising from Ofgem's decisions on the Gas TO investment plan or how the future use of the NTS by our customers has been factored into consideration on constraint risk. In the case of CCM specifically, we believe Ofgem have unjustly and simplistically extrapolated RIIO-1 performance to propose a RIIO-2 scheme. In doing so this has placed significant weight on the flawed conclusions arising from AFRY's Network Capability audit and, at a principle level, is at odds with the current commercial regime that has been deliberately designed for us to overselling capacity, which potentially reduces wholesale energy prices for consumers, with NGGT managing the inherent risk through the CCM incentive.

Remedies needed:
Review new information that demonstrates the consumer value of ODIs and set improved incentive values that would drive service improvements for consumers.

3.2 Efficiency – Opex and future efficiencies
We are deeply concerned regarding the level of efficiencies being applied to the NGGT business plan. We have responded to the specific questions (Chapter 5 of Core Document Q10 and Q11; Chapter 4 of NGGT Annex Q38) and this summarises the principle issues and remedies needed in the Final Determinations.

During RIIO-1, we have overspent our RIIO-1 allowances by over £300m, as it was in the interests of consumers to do so. This has meant that we already have an extreme focus on efficiency to deliver at as low a cost as possible.

Ofgem states that RIIO-2 should "push networks to be more efficient with stretching ongoing efficiency targets and lower sharing factors." We responded to the challenge to be stretching and ambitious, proposing the highest ongoing efficiency targets of any network business plan on top of external benchmark and historic trend evidence that demonstrated our costs were at frontier as we started the RIIO-2 period.

For our RIIO-2 business plan, we started with the efficiencies achieved in RIIO-1, including £30m identified by a suite of coordinated initiatives that will deliver by March 2021 and bring costs in line with external benchmarks. On top of this we overlaid a further 8% efficiency ambition for our RIIO-2 plan, which included 1.1 per cent per annum productivity growth target for all our opex costs. This is almost three times the current UK trend, representing a stretching target on top of the costs that are already at the efficiency frontier at the start of RIIO-2

Errors in Draft Determinations
During our analysis of Draft Determination, we have identified errors of computation and calculation increasing allowances by approximately £80m (excluding a further £51m resulting from incorrect capex figures used in the indirect cost modelling) and errors decreasing allowances by £41m. We have shared these with Ofgem during the consultation period and explain these issues in response to our detailed questions.

The most material errors are as follows;
- 1% error in the opex efficiency challenge applied across our plan reducing our allowances by a further £41m;
- double disallowance of Closely Associated Indirect (CAI) capex costs to the value of £77m. Ofgem has reduced our indirect allowances twice (once from a bottom up project assessment and then again through a top down gross CAI assessment) for our capex activities resulting in a negative allowance of £12m for our CAI capex costs.
- other smaller errors across various categories across opex categories totalling a further £3m increase to allowances.
- Ofgem has applied arbitrary ongoing efficiency targets which are above regulatory precedent, based on flawed analysis, including a 0.2% 'innovation wedge' that is entirely without basis.

- A flawed top down econometric approach to our operating costs, resulting in a 60% reduction in our CAI allowances. This results in us being unfunded for mandatory activities such as maintaining compliance with our safety case and legislative environmental compliance including the operational training of our field force and retaining the engineering expertise to assess network risk.

We've agreed these errors with Ofgem and our remedies reflect these figures as our starting point. In this context, Ofgem's proposal to disallow 30% of our business plan on the grounds of efficiency goes far beyond the definition of "stretching", employing flawed decisions based on analysis that has significant errors. In their assessment Ofgem has:

- Disregarded the contents of 15% of our business plan relating to indirect costs and instead set its own view, using an unreliable econometric modelling approach that incorrectly assumes comparability between gas transmission (in a sector of one) and electricity transmission networks. Even the flawed methodology does not support the rejection of our costs as inefficient on a statistical basis as Ofgem has.
- Scaled down Closely Associated Indirect costs in proportion with capex levels, ignoring that half of operating activities do not flex with the scale of our capital programme and also resulting in a double counted disallowance of £77m for those activities that do support capital projects
- Proposed opex escalator funding based on the same flawed modelling which only provides partial funding for our project management activities associated with uncertainty mechanism-funded capital projects, leaving network activities exposed for the full five years
- Cherry picked between historic and future unit costs, resulting in a sub-efficient level of allowances that embeds networks ongoing efficiency targets into baseline unit costs
- Failed to add in allowances for activities such as cyber, EAP and electric vehicles operation despite agreeing with the need for these activities
- Added further pressure by layering on above-regulatory precedent targets for ongoing efficiency that are based on an unnuanced interpretation of flawed analysis, including a 0.2% "innovation wedge" that is entirely without basis

Ofgem's proposal puts at risk the safety and resilience of our network today; by underfunding our incremental health and safety costs, ongoing operational training to maintain workforce competencies and other opex costs required to meet our HSE-approved safety case. It also undermines the resilience of our network in the future by failing to fund the recruitment and upskilling activities we built into our plan to ensure we maintain a skilled and diverse workforce in light of a projected 19% workforce retirement over the next 10 years. And these decisions threaten the timely transition to a Net Zero future. Faced with this level of cuts to core activities there is no option but to renegotiate our safety case with the HSE and completely eliminate activities over more discretionary areas such as engineering support to progress net-zero and hydrogen work.

To address our concerns, we outline the remedies required to DDs.

Remedies needed:
In reaching Final Determinations Ofgem needs to follow a more appropriate cost assessment methodology that:

- Removes NGGT from indirect regression analysis, recognising the fundamentally different cost structures prevent meaningful comparison with the ET sector
- Assesses indirect capex costs as part of the capex cost assessment process
- Places greater weight on submitted efficiency evidence for net operating costs; for CAI that means assessing against historic trends, for business support costs against efficiency benchmarking evidence
- Assesses the evidence for the limited additional funding we are seeking to maintain our network, maintain a resilient workforce for the future and to insure our business assets;
- applies an ongoing efficiency target that is appropriately stretching in the context of current economic conditions; and
- corrects the £77m double count and other errors that pepper their Draft Determination.

3.3 Totex incentive mechanism (TIM)

Ofgem has proposed a TIM sharing factor for NGGT of 37.1% compared to 44% in RIIO-1. We have identified an error in the methodology, which has led to the sharing factor being understated. In addition, we set out an approach that we believe aligns with Ofgem's policy intent and accounts for costs that will be assessed through uncertainty mechanisms and protected through additional framework tools, such as PCDs.

Ofgem state that costs funded through reopeners, volume drivers and 'use it or lose it' uncertainty mechanisms (UMs) are excluded from their confidence assessment. We have identified that this policy has not been implemented correctly with the current calculation using high confidence costs and total baseline including UM. Correcting for this error results in a sharing factor of 40.35% based on Ofgem's Draft Determination proposals. The calculation must be corrected in Final Determinations.

We do not believe Ofgem have fully considered stakeholders' legitimate concerns in the design of the TIM sharing factor methodology in its sector-specific methodology decision. This has led to TIM sharing factors that are too low, reducing incentives to drive lowest cost outcomes for consumers or protecting them from passing on inefficient costs. In addition, the broader framework includes many new mechanisms to limit and protect from any windfall gains or losses to networks which should allow a higher sharing factor. Notwithstanding this, there are several flaws in the methodology and how it has been applied.

- Ofgem's approach results in an outcome which is biased against transmission companies and as a result leads to them inevitably receiving lower sharing factors;
- Ofgem's approach does not reflect the true cost confidence of spend subject to uncertainty mechanisms; and
- Ofgem's approach does not take account of additional tools added to the RIIO-2 framework to increase cost certainty for lower-confidence costs, such as mechanistic PCDs.

Ofgem's application of the TIM sharing factor calculation produces a result which is systematically biased against transmission companies.

- The result of Ofgem's application of its TIM methodology is for sharing factors varying between 30.9% and 39.2% (average: 36.5%) for the four transmission companies and between 49.4% and 50% (average: 49.7%) for the four gas distribution companies.
- Ofgem is placing most weight on a subset of one of the four ways to prove costs are high confidence, SSMD paragraph 11.37: econometric industry benchmark evidence. This method is not available to the transmission companies as there are an insufficient number of companies and because of their disparity in size and networks. The assessment against the other three ways to demonstrate high confidence is not consistent with the Principles of Better Regulation reflected in the Gas Act that require Ofgem to have regard to "the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed" because of the wide discretion Ofgem has given itself in its limited guidance. Ofgem's approach makes it materially harder for a transmission company to show it has high-confidence costs.

Ofgem's approach of just looking at current high confidence costs does not take account of the broader framework in place to ensure cost confidence. Ofgem is requiring companies to set low baselines with a large amount of RIIO-2 expenditure funded through uncertainty mechanisms (UMs).

- Ofgem's approach does not take account of costs that will be in uncertainty mechanisms, when its SSMD 11.37, main paragraph and fourth bullet point says, "We consider that the following types of information may be relevant to Ofgem's consideration of whether certain costs should be classified as high-confidence baseline costs […] Costs where we are able to determine a unit cost allowance with a high degree of confidence and where an appropriate volume driver or other uncertainty mechanism will be implemented and applied to a volume drawn from a baseline scenario volume". Ofgem has included no such costs in its calculation of the TIM

sharing factor, despite clearly signalling that it would. As a result, it has underestimated the proportion of costs that should be considered high confidence.
- For reopener UMs, one of the main purposes is for Ofgem to have more certainty over network companies' costs, SSMD paragraph 9.7. Ofgem should include an estimate of the costs that it will approve during RIIO-2 which should be added to NGGT's high-confidence costs because they will have been subject to an Ofgem specific review. For example, an estimate of the total likely investment has been made to assess financeability (Ofgem have used £2.7bn in the "illustrative" totex scenario which has been included in Ofgem's Licence Model) and it would be prudent to use a consistent figure throughout including for the TIM calculation. This will increase the proportion of high-confidence costs in the TIM calculation.

The introduction of Price Control Deliverables (PCDs) provides a high level of protection and cost confidence to consumers. The intent of the framework is to hold network to account for delivery of outputs and requires that funding for any outputs not delivered is returned. Given the PCD mechanism, the TIM methodology should treat all ex-ante cost covered by a PCD as high cost confidence given costs may adjust in the event of a change to the output being delivered (automatically for mechanistic PCDs).

It is important that a fair estimate of the high-confidence costs that will be achieved across RIIO-2 is used to calculate the TIM sharing factor. As a minimum Ofgem should accurately reflect its policy outlined in Draft Determinations core document paragraph 10.23 to exclude UM costs from the TIM sharing factor calculation and treat PCD costs the same way given the equivalent protection is provided.

Remedies needed:
- Correct the error in calculation of the TIM sharing factor.
- Account for the wider RIIO-2 framework in the assessment of high-confidence costs by assessing those to be provided through uncertainty mechanism and protected through additional framework tools, such as PCDs as high-confidence.

3.4 Business Plan Incentive mechanism

We strongly disagree with Ofgem's proposed assessment of NGGT's business plan.

Ofgem's proposed fine of £26.4m and disallowance of rewards under Stage 2 of the BPI is wholly disproportionate to the circumstances. The proposed imposition of such a material penalty in the absence of any compelling justification or properly reasoned submission is unacceptable.

Ofgem should change its assessment of NGGT's business plan as we describe in the remedy section below because:
- There were flaws in the development of the BPI;
- The design of the BPI is flawed; and
- The application of the BPI to NGGT is flawed.

Flaws in the development of the BPI

There were fundamental flaws in the development of the BPI.
- Ofgem changed the BPI profoundly in its sector-specific methodology decision (SSMD) that it published on 24 May 2019 and Ofgem did not consult on its new approach.
- The BPI is supposed to incentivise network companies to produce ambitious plans, but Ofgem only published its new BPI five weeks before companies had to submit full draft business plans on 1 July 2019. Indeed, at an Ofgem working group on the BPI on 19 June 2019, Ofgem said it had "not yet determined the methodology" for Stage 2 of the BPI.
- Having not just one, but two, draft business plan submissions provided Ofgem with plenty of opportunity to provide feedback if it had concerns with our business plan. In addition, we had frequent engagement with Ofgem in the process leading up to submitting our final business

plan. At no point did Ofgem suggest that the information provided in NGGT's draft plan fell short of the quality and completeness standards that the regulator had set.

The design of the BPI is flawed

The design of the BPI fails to deliver Ofgem's main aims for the BPI:

- Ofgem wants the BPI to encourage high-quality, ambitious and innovative business plans. The BPI has the opposite effect. Ambitious or innovative approaches face a much higher risk of a 10% penalty under Stage 3 of the BPI and these large penalties undermine the confidence of companies and investors in the stability and predictability of the regulatory regime.
- The BPI has made the business plan process more onerous on companies by the introduction of an untested and theoretically unsound mechanism. NGGT was required to submit a very large quantity of information in its business plan and accompanying BPDTs, and despite this, Ofgem's DD cites as the basis for failing NGGT under Stage 1 of the BPI numerous categories of information which were not directly requested in the BPG or BPDTs.
- The design of the BPI is flawed because it is heavily skewed towards penalties for transmission companies. Ofgem's proposed application of the BPI at the DD stage has resulted in net penalties for the four transmission companies of £140.2m, compared with a net reward of £0.4m proposed for the four gas distribution companies. The way in which Ofgem has designed the BPI unfairly penalises transmission companies due to features of the sector which are beyond their control, and Ofgem has not taken appropriate account of sector-specific differences.
- Ofgem's BPI prioritises one method of establishing cost efficiency, econometric industry benchmarking, over other methods. Ofgem does not use econometric analysis for the transmission companies. Across the sector, projects are typically larger, less frequent, less standardised and less repeatable. In relation to this, the limited number of companies even in the gas and electricity distribution sectors undermines Ofgem's preference for econometric benchmarking, given the poor statistical properties of a model relying on so few data points.
- The design of the BPI is also flawed because of the wide discretion Ofgem has reserved to itself when assessing compliance with the guidance, for example, around what constitutes a complete and satisfactory quality plan. Ofgem cannot reserve to itself such broad discretion in the application of the BPG.

The application of the BPI to NGGT is flawed

The Competition Appeal Tribunal has clearly established that penalties of the magnitude that Ofgem is proposing to apply to NGGT are "serious" and that "strong and convincing evidence will be required" to justify them. Ofgem's summary in its DD of the alleged deficiencies in NGGT's business plan falls far short of this standard.

Stage 1 – Ofgem has wrongly applied the framework to provisionally conclude – incorrectly – that our business plan did not meet the Minimum Requirements, and that this was sufficiently material to warrant failure against BPI Stage 1. Where a specific type of evidence was required under the BPG, Ofgem misapplied its framework by imposing a higher standard than that specified as a Minimum Requirement or failed to properly take into account the evidence that we submitted with our business plan. Ofgem also did not take any account of the views of Independent User Groups (IUGs) in assessing whether the Minimum Requirements for Stage 1 have been met.

Stage 2 – Ofgem accepted only two of NGGT's nine Consumer Value Propositions (CVPs) and moreover concluded that NGGT was not eligible for a reward in respect of this CVP proposal due to its Stage 1 decision. Ofgem should reconsider their decision to reject NGGTs CVPs for Blackrod and Business Carbon Footprint as our commitments go demonstrably beyond Business as Usual (BAU). Ofgem's DD only proposed to accept three CVPs across all network companies, with an up-front value of £3.2m, out of the 117 CVPs network companies submitted, which shows a serious failure on the part of Ofgem to effectively communicate its expectations to network companies.

Stage 3 – Ofgem has a skewed approach to assessing whether companies' costs proposals which it deems "lower confidence" are sufficiently justified. In making this assessment, Ofgem reviews a range of cost data which is often not available to companies, and systematically targets the lowest cost, imposing a Stage 3 fine where the company's submission was above that cost. This is not a reasonable approach for assessing the quality of a business plan: Ofgem should be taking into account whether a company's proposal was justified on the basis of the information available to it.

When assessing whether "lower confidence" costs were "poorly justified", Ofgem has then penalised companies if their proposed costs exceeded those associated with Ofgem's preferred option, without making any adjustment for the higher level of service / output which companies were proposing. This is not a logical basis for comparison as it is clearly wrong to base an efficiency assessment on costs alone without also taking into consideration the level of output. We have provided detailed evidence against Ofgem's erroneous position on the individual cost categories in this annex

Stage 4 – This appears to have been an empty process designed to give the BPI the appearance of balance, by giving the BPI two reward stages to balance the two penalty stages. Ofgem applied no rewards to any of the eight network companies under stage 4.

Our full response to the BPI can be found in NGGT Annex Business Plan Incentive. Further detail on Stage 2 can be found in NGGTQ16-19 and on Stage 3 in NGGTQ25-26.

Remedies needed:
We propose that Ofgem give consideration to the flaws in this process for the transmission companies and consider a net position of all four stages. For NGGT this would encompass the removal in full the penalty of £7.8m at Stage 1, application of the rewards earned through Stage 2, removal in full of the Stage 3 penalty of £18.6m and applying a meaningful reward in Stage 4 to those areas of NGGT's costs that helped Ofgem with its cost assessment process.

3.5 Interlinkages and Appeals

The Draft Determination sets out a proposal that Ofgem would include in the Final Determination a statement of policy of its intent to carry out a post-appeal review following a successful CMA appeal against its price control decision "…where this would be of assistance in ensuring the overall coherence and consistency of the regulatory settlement". This proposal is unnecessary, and we are seriously concerned by any proposal suggesting that Ofgem might seek to, in its view, redress the balance following a successful CMA appeal. This would clearly undermine the CMA appeals regime and it is surprising that the Draft Determination leaves this open as a possibility.

The proposal is unnecessary under the existing legal framework, because the CMA is not only able to consider any issues around knock-on impacts from a successful appeal as part of the appeal process but has been willing to do so in each appeal process conducted. Any view Ofgem has that a ground of appeal raised would, if successful, have such a knock-on impact can and should be raised in its submissions to the CMA. The CMA can then determine the matter or give directions on any knock-on impacts which need Ofgem's further consideration.

The scenarios given in the Draft Determination for where a post-appeal review could be conducted involve the CMA giving a direction to Ofgem. Ofgem already has a statutory duty to comply with any direction. There is no reason for a policy statement in the Final Determination confirming this – Ofgem would be doing no more that setting out the existing position.

However, the Draft Determination states that the scenarios given are not an exhaustive list. We would be extremely concerned if Ofgem's proposal meant that Ofgem might seek to make adjustments for knock-on impacts through a post-appeal review with no decision by the CMA that it should do so. The proposal also leaves open the possibility that Ofgem might do this in areas where there is no clear knock-on impact but where Ofgem is considering broader factors in "the overall coherence and consistency of the regulatory settlement". In either case, it would be wrong for Ofgem to contemplate this:

- Ofgem makes its price control decision, in light of all relevant circumstances.
- Discrete elements of that overall decision may be subject to appeal on the basis of specific errors.
- Ofgem must implement the remedies from any successful appeal, including any decision relating to knock-on impacts on the other parts of the price control given by the CMA.
- In these circumstances, any broader revisiting of the decision would have the effect of undermining the CMA's findings and thereby frustrating the appeals regime.

The appeals regime is intended to provide effective rights of appeal to networks and the advancement of this proposal unnecessarily introduces uncertainty for licence holders about the predictability of the regulatory regime. A stable appeals regime is not only in line with best regulatory practice but is fundamental to a credible environment for investment in the gas sector. Any undermining of that stable regime seriously prejudices that environment and is detrimental to consumers.

It would also be entirely inefficient and a waste of both time and cost for any matter of contention around knock-on impacts to be determined only through a second CMA appeal (following a post-appeal review), where the issue could properly have been determined in the initial appeal.

3.6 NARMs Funding Adjustment and Penalty Mechanism

We do not agree with the proposed NARM Funding Adjustment and Penalty Mechanism, which gives Ofgem the ability to adjust our NARM funding at the end of RIIO-2. The overall impact of the complex mechanism is that it will cancel out any efficiencies earned by networks, unless in a granular way and after the event, the network can demonstrate that was an efficient decision. The mechanism moves networks away from managing the risk on the network for consumers, ensuring we continue to maintain resilience and reliability to a mechanism that strongly incentivise us to deliver our business plan, exactly as it is set at the start of RIIO-2. It therefore strongly disincentivises us to behave as an efficient and effective asset manager ensuring we manage risk across the network as a whole.

We have identified the following issues that mean the mechanism, as currently defined does not work in practice:

- **Reduces incentive to manage asset health risk:** A basic principle of NARMs is to incentivise networks to manage risk across the network and to maintain resilience and reliability for customers. This discourages risk trading, with networks potentially favouring justifying outperformance of any one asset category and not seeking to manage risk at a network level and to ensure increase costs to manage risk are not passed onto consumers.

- **NARMs model insufficiently robust to support a UCR adjustment**: Ofgem will set our final NARM allowance as total "justified" volumes multiplied by a "Unit Cost of Risk Benefit" (UCR). The relationship between cost and the monetised amount of risk reduction that is delivered is complex and not uniformly correlated across asset types. This therefore means that the underlying principle of Ofgem's mechanism, namely that it is possible to calculate the UCR and adjust baseline allowances based on this, is fundamentally flawed.

- **Subjective judgements by Ofgem during close out will play a key part**: The NARM funding adjustment is applied by Ofgem ex-post with subjective judgements on granular interventions whether there have been any departures from the plan and whether these are "justified". We do not believe this can work in practice and does not allow our Directors or management teams to make decisions knowing the potential risk to funding, which is unacceptable. The principle of this ex-post adjustment means our asset health plan is no more than a reopener uncertainty mechanism.

- **Weak incentives for efficiency and skewed downside risk**: Ofgem will adjust the UCR by up to 95% to take account of any outperformance that it does not consider genuinely efficient whilst we remain fully exposed to any potential underperformance. From our early analysis, this creates an asymmetric incentive and passes greater risk onto networks.

Ofgem have highlighted concerns with the existing methodology and, we believe there are solid alternatives that build on the existing foundation we have developed in the gas transmission sector. Ofgem highlighted the following metrics could lead to unearned performance during the price control. We have set out why this is not a concern for the gas transmission network. Where there is a concern, we have identified plausible remedies.

Table NGGT3 – NARMs

Metric Change driver	Issue created	Plausible remedy
Switching asset categories	We recognise, if work switches between asset categories, this can lead to increase or decrease in the cost per risk removed	For the vast majority of assets, the switch between categories has no material effect. For a limited number, isolating into a separate grouping and removing risk trading between groups would minimise the issue. We will discuss this further with Ofgem leading up to Final Determinations.
Switching schemes	Our NARMs mechanism does not operate at a scheme level so this is not an applicable concern for gas transmission.	N/A
Switching intervention types	Potential to undertake lower unit cost refurbishment rather than replacement activities to deliver risk benefits.	Over 95% of our plan covers refurbishment of assets with only 5% replacement and therefore this risk is eliminated. Further, Ofgem have already assessed our interventions as being at the efficient cost level to reduce the risk. Therefore, no further intrusive performance measures are required.
Asset Deterioration	The NARM and mechanism eliminates asset deterioration changes over the 5 years of RIIO-2, therefore this is not an issue.	N/A

Alternative NGGT performance mechanism

To mitigate the risks of trading, eliminating the potential for windfall gains or windfall losses as well as our concerns with the proposed NARM Funding Adjustment and Penalty Mechanism, we propose an alternative option based on the Incentives Methodology in RIIO-1, which was consulted upon and agreed at the point when our RIIO-2 plan was submitted. This is a solution that will avoid complexity, allow management teams and Directors to be able to explain both risk and financial performance over RIIO-2 period.

The mechanism focuses on eliminating the concern Ofgem has on workload switching between asset categories. We propose a mechanism that will remove interventions likely to result in excessive under delivery or over delivery of LTRB from the NARM mechanism using a statistically robust outlier process. Additionally, if the RIIO-2 value of the removed interventions exceeds £1m, we would propose these as volume based ring-fenced PCDs. We also propose to retain a materiality threshold to avoid the need to justify under or over delivery for all interventions in the plan. This is explained further in NARMS questions 1-4.

NGGT NARM model errors and categorisation

For the Draft Determination Ofgem have restated our BNRO target following proposed volume reductions for our Asset Health work. We highlighted errors in the provided Ofgem NARM Model, which have been fed back to Ofgem and we have offered to work with Ofgem to ensure the NARM Model reflects our correct target for RIIO-2. It is important that we can restate our NARMs analysis using the same approach used for the December business plan submission, rather than the simplistic approach adopted by Ofgem documented in the Draft Determination NARMs annex.

In general, we agree with Ofgem's proposal of funding categories, although for Cyber interventions these should be treated the same as non-lead Asset Health interventions, which are delivered under a separate PCD and not counted towards our BNRO. We have also highlighted a few issues relating to the treatment of indirect interventions and volumes to be determined by reopeners in our response to questions in the NARMS questions 1-4.

Remedies needed:

- Accept our alternative NARMs mechanism that simplifies regulatory regime whilst maintaining protection for consumers
- Allow us to restate our NARMs table following Final Determination using the allowed interventions and volumes

3.7 Finance

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

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

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

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

- **Inadequate equity returns:** The proposed allowed equity return is below that of the UK water sector and most comparable international benchmarks. This level of return is far too low for a transmission company, owing primarily to errors in setting both beta and total market return and the inclusion of a flawed outperformance wedge. Ofgem's proposed beta is not in line with the fundamental drivers of higher risk for energy compared to water, such as capex complexity, stranding risk and energy transition uncertainty. Nor does it take account of empirical evidence in the DD which shows National Grid plc's beta has been higher than the proposed beta and those of the water sector over the last ten years.

- **A marked weakening of financial resilience**: The lower returns in RIIO-2 sharply reduce financial resilience with baseline plans leaving the notional company on the cusp of being downgraded from Baa1 / BBB+, Ofgem's target rating. More worryingly, notional credit metrics drop to sub-investment grade once cashflow risk caused by delays between spend and revenue under uncertainty mechanisms is factored in.

- **Unachievable allowed equity return**: With the application of disproportionate and unjustified Business Plan Incentive (BPI) penalties, higher than ever efficiency cuts, and a flawed outperformance wedge, Ofgem has placed an unprecedented challenge on our business at the start of RIIO-2. As a result, equity returns would only be 2.7% without any savings to current operations, 150 basis points (bps) below the allowed equity return. With minimal potential upside from incentives and totex performance the framework offers unprecedentedly low opportunity to close the gap despite the need for innovation to deliver the energy transition. In combination, this means that investors cannot expect to deliver the allowed equity return - a fundamental tenet of the regulatory regime, which is clearly inconsistent with Ofgem's statutory duties.

Response to Ofgem questions NGGTQ1 to NGGT39

2. Quality of service - setting outputs

Common ODIs

NGGTQ1. Do you agree with our proposals for the Customer Satisfaction ODI-F?

Yes, we agree with Ofgem's proposals for the customer satisfaction ODI-F and the revised performance target of 7.8/10 based on improving performance from RIIO-1. We acknowledge the role of the User Group in identifying the range of customers that could be surveyed.

NGGTQ2. Do you agree with our proposals for the Quality of Demand Forecasting incentive?

Whilst we support the continuation of a D-1 Demand Forecasting incentive, we disagree with Ofgem's proposals for the Quality of Demand Forecasting incentive. Based on the parameters proposed by Ofgem, it does not provide any incentive to improve, or indeed maintain, forecasting performance. Furthermore, the scheme fails to recognise the different and challenging RIIO-2 landscape, (in particular the impact that demonstrable increases in supply and demand volatility will have on the performance of this ODI). The scheme is solely based on historic RIIO-1 performance, does not take account of the challenges faced in RIIO-1 and the increasing challenges of RIIO-2 and is inconsistent with the stakeholder feedback we received in relation to the value of this scheme.

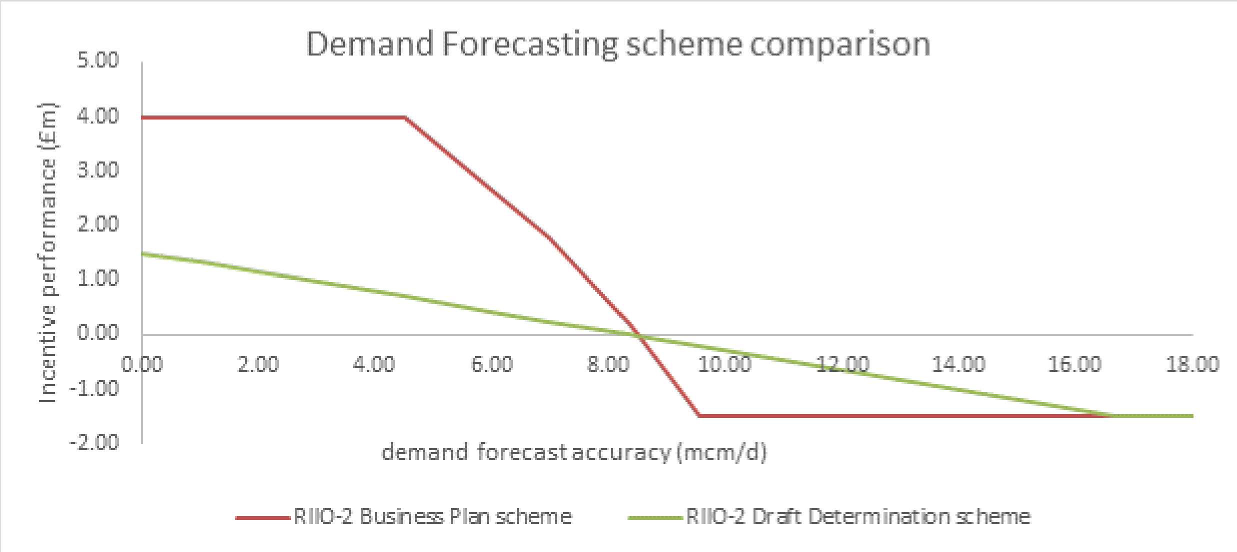
We are also disappointed that Ofgem appear to have not considered or justified the exclusion of AFRY's recommendations. These were to seek and act on further information, such as the usefulness of other forecasting data (including within-day updates to the forecasts) to help inform the value of the demand forecasting incentive or a potentially expanded demand forecasting incentive and sector specific data. Where able to, we have included further information in this response and supporting NGGT Annex Output Delivery Incentives.

We do not agree with the removal of the D-2 to D-5 scheme, this scheme was supported by stakeholders during our RIIO-2 engagement. We did not include any specific quantifiable consumer value relating to D-2 to D-5 as it was not possible to quantify this in the same way as D-1 (validated by independent consultants and stated in our December business plan) as there is not a direct impact between that forecast and price. However, we believe, as AFRY also recognise in their report, that the consumer benefit demonstrated and quantified for the D-1 scheme can be logically extended to the D-2 to D-5 scheme. We also note that the D-1 scheme has been more widely supported but believe that the provision of the D-2 to D-5 service provides a level playing field for those customers and stakeholders who have not got their own demand forecasting capability to inform their commercial and balancing decision making. Removal of an incentive in this area means it is practically impossible to justify investment in D-2 to D-5 forecasting accuracy improvements and therefore as volatility increases, performance in this area will decline.

It is also important to note that both the D-1 and D-2 to D-5 incentive schemes proposed by National Grid were developed with the input of stakeholders, and that the parameters put forward in our December business plan were broadly supported. Therefore, Ofgem's decision to alter the schemes so significantly, represents a wholesale disregard of stakeholder views and risks damaging the performance of incentives that provide clear consumer value.

Ofgem's proposed incentive design, adjusts the target, cap and therefore the incentive strength. This is illustrated by comparing the graphical representation of our business plan proposed scheme and Ofgem's Draft Determination scheme below (assumes storage adjuster of zero):

Figure NGGT4 - D-1 Demand Forecasting Scheme Comparison



Our views on each of the scheme elements is provided below:

Incentive Cap: We disagree with the proposed 85% reduction in incentive cap to £1.5m and the flawed rationale underpinning it. We proposed a financial cap of £4m which would only be achieved if annual forecast accuracy was better than 4 mcm/d, compared to our best RIIO-1 annual performance to date of 7.75 mcm/d. Ofgem have rejected our proposed cap on the basis that it would rarely, if ever, be hit in RIIO-2, yet proposed an alternative cap of £1.5m which is not possible to achieve given that this would require 100% accuracy 365 days a year. We continue to believe incentive caps should be stretching but achievable to encourage improved performance.

Ofgem's proposed scheme cap (and subsequent reduced incentive rate) discourages further investment in improving forecast accuracy. This is directly at odds with stakeholder views as they have expressed a desire for further demand forecasting accuracy improvements. Under the proposed incentive scheme, we are unlikely to invest in this area above maintaining our UNC obligations and therefore the forecast accuracy is likely to decline from RIIO-1 levels, this creates lost value for customers and consumers who use the forecast information for their own business purposes.

Incentive Rate: We do not agree with the proposed incentive rate or AFRY's conclusion that the impact of the RIIO-2 proposals on incentive revenue performance would be limited. In our business plan we highlighted that a lower cap would reduce the incentive rate and result in a lower incentive reward for RIIO-2 compared to the same level of performance in RIIO-1. The Ofgem Draft Determination document and the AFRY demand forecasting annex concluded that our proposed schemes would result in only a 2% decrease in earnings from the incentive. This is factually incorrect. Our RIIO-2 proposed scheme would actually result in a circa 20% decrease in financial performance compared to RIIO-1 as illustrated below. We are very disappointed that an error of this magnitude has been used as a basis for the Draft Determination scheme.

Table NGGT5 - Comparison of Demand Forecasting Performance under the RIIO-1 and proposed RIIO-2 Incentive Schemes

Regulatory year	Forecast accuracy (mcm/d)	RIIO-1 scheme (£m)	RIIO-2 BP scheme (£m)	% difference
2013/14	8.91	0.88	0.71	20%
2014/15	8.07	1.54	1.23	20%
2015/16	7.75	1.96	1.56	20%
2016/17	8.53	1.51	1.21	20%
2017/18	8.24	1.39	1.11	20%
2018/19	8.90	-0.86	-0.56	35%*
2019/20	8.56	0.99	0.79	20%

*due to effect of negative storage adjuster

Ofgem's rationale of setting the cap at £1.5m to be closer to our RIIO-1 average performance is not a sound basis for a scheme dependant on the financial cap and collar to set the performance gradient of the scheme. Under the proposed scheme a 1 mcm/d improvement in demand forecasting accuracy equates to circa £180k per annum vs circa £1.1m under the RIIO-1 scheme. As a comparison, for one element of the D-1 forecasting model in RIIO-1 we have invested [redacted] to improve its performance, under the Draft Determination scheme this would require an improvement of a circa 2.5mcm/d in one year or 0.5 mcm/d over each year in RIIO-2 for that element to begin to justify the investment compared to a circa 0.1mcm/d improvement over a 5 year period under the RIIO-1 scheme. There appears to be no rationale provided to justify an 84% reduction in the incentive rate of return which significantly dampens the incentive to invest to deliver improved forecast accuracy for the benefit of customers and consumers.

Incentive Target: We disagree with the proposed incentive target of 8.35 mcm/d and the rationale underpinning it. Ofgem have stated that this target has been derived by using RIIO-1 actual performance. We do not agree with this approach as it does not take into consideration the future supply and demand volatility that will result in a more challenging forecasting landscape. This is already demonstrably evident within RIIO-1 where increased day-to-day demand volatility has presented a significant challenge in meeting the existing 8.5 mcm/d target. We have detailed volatility and D-1 performance across RIIO-1 in the table below. For example, in 2018/19 average day-to-day change in national demand increased from 12.18 mcm/d to 13.78 mcm/d, with 18 days showing a greater than 40 mcm/d change from the previous day (the most extreme of these daily demand changes was 86.67 mcm/d). This resulted in negative incentive performance of -£0.86m. For comparison, our best historical performance in RIIO-1 was achieved in 2015/16 with demand volatility of 10.89mcm.

Table NGGT6 - RIIO-1 Demand Volatility and D-1 Demand Forecasting Performance

Date	Ave Volatility (mcm/d)	Min Volatility (mcm/d)	Max Volatility (mcm/d)	D-1 Accuracy (mcm/d)	Performance £m
2013/14	11.27	0.01	63.42	8.69	0.88
2014/15	10.51	0.02	60.28	8.07	1.54
2015/16	10.89	0.05	47.61	7.75	1.96
2016/17	11.54	0.03	63.9	8.53	1.51
2017/18	12.22	0.05	66.49	8.24	1.39
2018/19	13.78	0.39	86.67	8.9	-0.86
2019/20	13.51	0.01	65.6	8.56	0.99

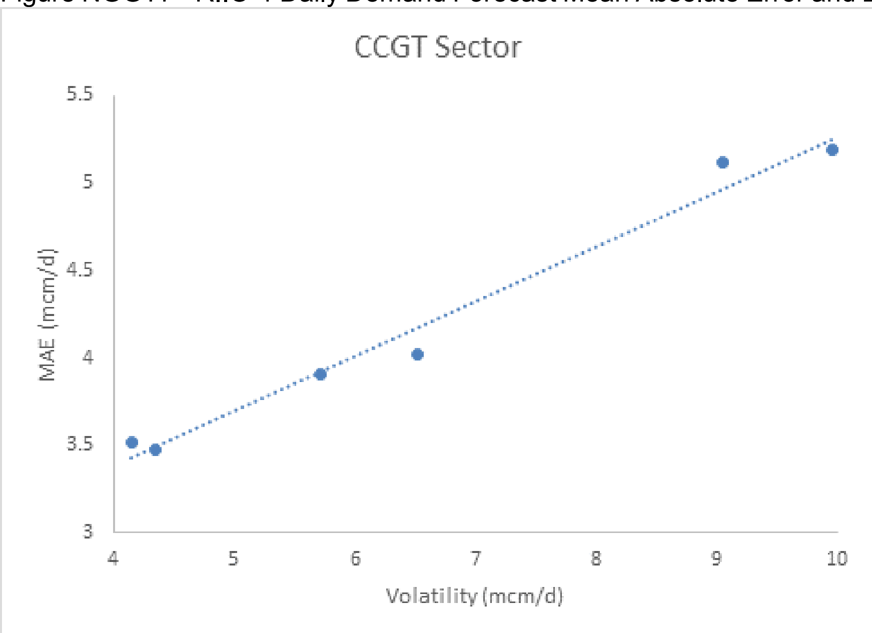
In our RIIO-2 Business Plan we highlighted that a growing rise in average demand volatility (~20% increase over RIIO-1 to date) was having an adverse impact on our ability to maintain and improve demand forecast accuracy.

Ofgem's proposal is underpinned by an assessment undertaken by AFRY in which they state that they are not convinced by the relationship between variability, volatility and forecast accuracy. We are disappointed and surprised that volatility is not referenced in, or forms any part of, Ofgem's Draft Determination as this was a key element underpinning our business plan. However, from AFRY's report this assumption would appear to be based on lack of sectoral analysis which we have now provided as part of the Annex to this Draft Determination response. With regards to the relationship between volatility and forecast accuracy, AFRY acknowledge that: 'while for recent years there appears to be a correlation between the two, sufficient evidence has yet to be provided that the correlation is a long-term trend'. However, AFRY also note that: 'a number of factors affecting the changing nature of the gas demand (e.g. the increased volatility of gas demand for electrical generation due to changes in the generation mix) have been known since before the commencement of RIIO-1'.

We find the latter point at odds with the first and would point out that by AFRY's own admission there is a known trend of increased demand volatility, at least in some sectors, that was present prior to RIIO-1. This means that the trend of increased volatility extends for, as a minimum, more than eight years. Whilst we accept that it is difficult to produce evidence of long-term trends when the issue is only emerging, we believe that a period of increased volatility and corresponding Mean Absolute Error (MAE) that has lasted for more than eight years, provides sufficient evidence to support our assertion. Furthermore, no evidence is provided by Ofgem or AFRY to disprove this correlation or its expected longevity.

The graph below shows the annual average MAE for the day ahead demand forecast against volatility (using daily data sets from 2011 through to the end of 2019), which is the absolute difference between today and yesterday's actual gas demand values. The CCGT demand sector view is shown below (for equivalent graphs for each demand sector please see NGGT Annex Output Delivery Incentives). There is a clear correlation between D-1 forecast accuracy and volatility, with a rise in volatility triggering a corresponding increase in forecast error. We believe this provides the necessary and demonstrable evidence to support the linkages between demand volatility and MAE.

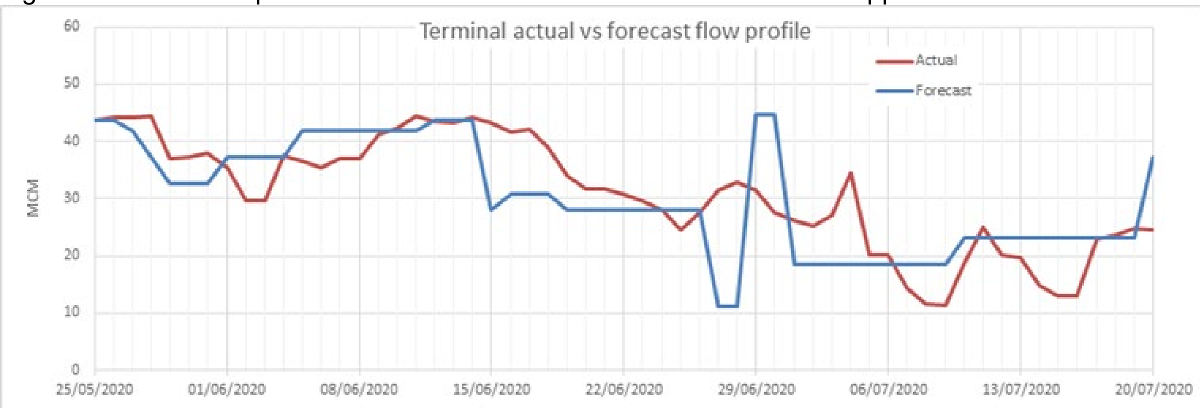
Figure NGGT7 - RIIO-1 Daily Demand Forecast Mean Absolute Error and Demand Volatility for CCGT Sector



It is important to note that volatility in supply also impacts demand forecasting as supply can drive demand. The chart below represents data received from one of the LNG terminals and highlights the difference between their supply forecasts and the daily actual flows over a recent 2 month period, with days of both under and over forecasts.

The increasing commercial flexibility in supply source and globalised LNG markets means even the terminals themselves have little ability to be able to accurately predict their flows ahead of real time. Forecasting supply more accurately is becoming increasingly difficult and will have a consequential impact to the accuracy of demand forecasting.

Figure NGGT8 - Comparison of an LNG Terminal Forecast and Actual Supplies



Whilst we have endeavoured to drive improvements in demand forecasting throughout the RIIO-1 period, the rise in supply and demand volatility has highlighted that we need to continually invest in our models to ensure that our existing models are continually updated and adapted to, at a minimum, keep pace with the ever-changing market.

The RIIO-1 incentive package struck the right balance between risk and reward, incentivising us to go beyond our UNC requirements, and provided financial incentive to encourage further investment in this area. As such, we have sanctioned several projects, aimed at improving forecasts for influencing factors. This includes, for example, the introduction of advanced technologies in the form of models that use machine learning for forecasting of sectoral demand and therefore reduce the associated MAE. This type of technology alone has a significant cost implication, [redacted]

Ofgem's proposed scheme discourages further investment such as the above by not providing an appropriate incentive and would therefore mean that investment aimed at improving accuracy in RIIO-2, would be at risk. For example, all other things being equal, if we spent £1m on improving the model(s) this would need to improve forecast accuracy by circa 5.5mcm in one year or by 1.1mcm per year over a 5-year period to generate a return which would be better than any single year performance improvement in RIIO-1.

To demonstrate this, we have applied the annual RIIO-1 day ahead demand forecasting performance (inclusive of the storage adjuster) to the Draft Determination scheme. Running the RIIO-1 forecasts through the incentive calculation as defined in the Draft Determination National Grid would, over the full RIIO-1 period, have made approx. £0.5m in incentive revenue; a reduction of almost £6m against RIIO-1 actual performance. Based on these figures the revenue generated over the RIIO-1 period would be less than has been invested to date on improving demand forecasting accuracy.

Given the increasing supply and demand volatility, the Draft Determination scheme provides insufficient financial incentive to maintain, let alone improve the demand forecast accuracy. By reducing the incentive gradient so significantly and including a cap that is unachievable (i.e. to cap out under the scheme, we must produce a forecast with a zero error for every day of the year) Ofgem has removed the incentive to invest to drive improvements which is not in line with customer and stakeholder feedback and risks loss of consumer value.

Further information on Demand Forecasting can be found in a supporting Annex (NGGT Annex Output Delivery Incentives), this includes more details on the key points raised above and additional graphs to demonstrate individual sectoral volatility.

NGGTQ3. Do you agree with our proposals for the Maintenance incentive?
We do not agree with the proposed maintenance incentive as a downside only scheme, as this is not aligned with stakeholder views and value expressed during the development of our business plan. The existing incentive has directly and demonstrably resulted in improvements for customers, which we have worked hard to deliver. From our engagement we know that our customers value the current scheme, supported our proposed scheme and want us to continue to seek improvements during RIIO-2 and this is not reflected in these proposals.

In our business plan we proposed increasing the scope of the incentive to capture maintenance days for non RVO maintenance at exit points. This reflected stakeholder feedback on the value the incentive had delivered for RVO's and we were seeking to widen the scope of the incentive to cover other maintenance that can impact customers.

We do not believe it is appropriate that we penalised for proposing to widen the scope of the ODI in line with the needs of our customers. This approach does not appear to be good regulatory practice as in the long term it will discourage networks from proposing new incentive elements if they are to become penalty only mechanisms from day 1.

Stakeholders have told us that they want us to minimise any disruption to them being able to put gas on and take gas off the transmission network. In terms of planned maintenance this means minimising the use of maintenance days and once the maintenance plan is in place, minimising the level of National Grid driven change to this plan.

Under the existing incentive and the proposed improved version in our business plan, the design of the incentive encourages us to minimise the number of maintenance days called and to minimise the amount of National Grid driven change to this plan. This is strongly aligned with stakeholder requirements.

Ofgem's proposed incentive scheme does not align with these stakeholder requirements. By adopting a downside only scheme with target number of maintenance days and amount of change, Ofgem has removed all incentive to improve performance that our customers supported. Providing target levels of maintenance days and level of change are not exceeded there is no incentive to minimise the impacts of maintenance on directly connected customers. We continue to believe the incentive should contain an upside as outlined in our business plan submission.

As an example, when considering moving a planned maintenance task, under the current arrangements there is a balance to be struck between the costs to the Gas Transmission Owner associated with moving the maintenance and the impacts under the incentive. Under Ofgem's proposal this balance is changed. For example, when considering work that could impact customer flows, using additional maintenance days may become a cheaper option than moving work or undertaking work in a different way that may incur additional costs for the Gas TO.

On a point of principle, we do not support calibration of the incentive target purely based on RIIO-1 experiences, rather than recognising the challenge of minimising disruption whilst delivering an increased volume of work in RIIO-2.

We note that in the consultation, Ofgem commented that we had not provided supporting evidence around the increased levels of work and the resulting increased congestion when scheduling maintenance into the future. We do not agree with these statements and would highlight areas such as asset health and cyber where the business plan shows increased levels of work required to support safety, reliability and availability.

Whilst the annual average number of RVO's or ILI's on our network remains largely unchanged in RIIO-2 these works need to be scheduled in against this backdrop of increased levels of interventions on the network and hence incentive performance will be more challenging to achieve.

Further information on our views on the proposed maintenance incentive can be found in the supporting NGGT Annex Output Delivery Incentives.

NGGTQ4. Do you agree with our proposals for the CCM incentive?

We do not agree with Ofgem's proposals for the CCM incentive. Ofgem state the purpose of the CCM incentive is "To deliver an efficient overall cost of SO constraint management actions and encourage balanced risk versus reward decisions in the release of additional capacity". We do not agree with this narrow definition as it fails to recognise the wider impacts of this scheme (e.g. on balance of decisions on asset vs commercial or impacts on wholesale markets).

Stakeholders have told us that they want us to provide maximum access to the network and that we should minimise any disruption to their ability to put gas onto, and take gas off, the network. The existing constraint management scheme plays a key role in this, encouraging maximising the release of capacity to the market and actions to minimise the risk of, and costs to manage, any constraints on the network.

Our RIIO-2 performance has maximised the overall level of access provided to customers, allowing access to the cheapest sources of supply and increasing security of supply, both of which benefit all types of gas consumer. Levels of constraint are impacted by asset reliability and availability and as such the CCM has always been considered a deep incentive impacting both GSO and GTO activities. It is not clear how Ofgem have factored their Draft Determination for GTO into their CCM proposals (and vice versa).

By their nature the level of constraints on the network are difficult to forecast with a high degree of certainty, as they are influenced by customer choices over use of entry points and levels of local and national gas demand. In producing our RIIO-2 proposals we have carried out an increased volume and more complex analysis than ever before, all of which has been shared with Ofgem. This analysis is designed to show the overall directional level of risk faced by the GSO.

Historically constraints have been viewed as low probability, high impacts events, however we do not believe that setting the incentive scheme based purely on the historic levels of constraints observed is a sound approach. Recent history, e.g. at Milford Haven in 2020, has demonstrated that these events occur on a more frequent basis and therefore the risk going forward may no longer be low probability. Furthermore, this logic is fundamentally flawed as it fails to recognise the inherent value that the RIIO-1 CCM ODI has created as it has had the intended effect, specifically we have been incentivised to take the necessary actions to mitigate constraints and thus minimise disruption to the market (including wholesale prices) and consumers. Demonstrably this has been executed to good effect as there were no material constraints in RIIO-1. Although we recognise the difficulty of forecasting constraint risk, according to Ofgem's apparent logic the only way to demonstrate / prove the value of the scheme is for the risk to not be managed effectively and costs to be incurred but this would be to the detriment of both customers and consumers.

Ofgem has failed to recognise that the scheme in RIIO-1 was successful as it incentivised us to manage / take action to prevent these risks from impacting customers and ultimately consumers. In response to the existing incentive we have worked hard to avoid constraints, for example by rescheduling maintenance when required. As an example, in Summer 2016 high flows at the St

Fergus entry terminal occurred, coincident with planned compressor and pipeline outages in Scotland. As a result, we had to accelerate work to reinstate the pipeline to service and reschedule other pipeline and compressor maintenance to avoid constraints at the St Fergus Terminal. As another example, during RIIO-1 we have used innovative contractual and physical solutions to manage potential Bacton constraints. The costs of these contracts to the GTO were [redacted] This is an example of the sorts of activity that we have undertaken on behalf of customers to manage constraint risk.

It is the presence of a strong incentive that resulted in these outcomes. With a different scheme in place, the balance between various operational decisions may have been different and more constraints may have occurred. Lack of constraints during RIIO-1 should not be interpreted as low risk of constraints in RIIO-2. Ofgem also state that there is a significant risk that the constraint costs and incentive target contained in our business plan proposal are overstated. We have undertaken robust analysis and there is a risk that we have under or overstated constraint risk. As an example, should we experience a sustained period of high flows at a single entry point during a period of low national demand, there would be constraint risk above the level of our forecast. For example, during April and May 2020 up to 40% of GB's demand was met through a single entry point (Milford Haven). Similar circumstances were seen in 2019 at Milford Haven and in 2016 at St Fergus. Putting aside the use of physical optimisation and scalebacks we would also note that in 6 of the last 8 years we have taken out constraint management contracts to manage constraint risks on the network which demonstrates that the risks are real.

Table NGGT9 - Constraint Management Contract Costs Incurred

Formula year	Contract cost (£m)
2020/21 (to date)	[redacted]
2019/20	[redacted]
2017/18	[redacted]
2016/17	[redacted]
2014/15	[redacted]
2013/14	[redacted]

In the consultation, Ofgem state that the proposed scheme transfers risk from consumers to National Grid, which Ofgem clarified in a meeting with us on the 24 July was a comment primarily about costs to consumers under the scheme rather than the risk being managed. In a scenario where there is zero, or very low, constraint risk then we would agree with this statement as there would be little constraint risk to manage, or factor into long and short-term decision making. However, our analysis shows that there is constraint risk for RIIO-2 and we believe that it is not in consumers interests for a significantly weaker incentive to be introduced. The proposed scheme, coupled with the proposed DD for the TO, would be expected to impact the balance of future investment and operational decisions, which may lead to higher levels of realised constraints and disruption to customers, with consequential impacts to consumers. We do not therefore support the statement that the proposed incentive transfers risk away from consumers.

Under the current and previous incentive arrangements, we have made long term decisions that balanced investment in asset solutions against the level of commercial risk that we would accept and manage under the CCM incentive scheme. The scheme parameters we proposed under our business plan ensured that the balance of risk remained consistent with previous CCM arrangements. With Ofgem's proposed changes to the incentive scheme, this commercial risk is largely being moved to consumers and away from us. Consumers have no ability to manage this risk and it is not clear why they should be exposed to the commercial risks associated with our long-term asset investment decisions.

In addition to the changes to constraint risk, the proposed incentive also impacts the risk/reward balance around the release the capacity to market participants, particularly when performance is close to the incentive cap. We are not clear why this is believed to be in the interests of customers or consumers. Further independent assessment of this point can be found in NGGT Annex FTI Report.

From Ofgem's consultation documents and supporting Annex's it is not clear how the factors above have been included in Ofgem's analysis and proposed incentive. From discussions with Ofgem on the 24th and 31st July it is clear that the calibration of the scheme for RIIO-2 is based on RIIO-1 outturn performance and without recognition of the customer value delivered during RIIO-1 and how this may be detrimentally impacted by Ofgem's proposals.

We also note that the AFRY CCM Annex accompanying Ofgem's proposals includes a number of potential different incentive scheme designs, with pros and cons of each presented. Given Ofgem's view on our proposed incentive design, it is not clear how these alternate proposals have been assessed by Ofgem.

Ofgem's proposed incentive design, adjusts all of the parameters of the existing incentive scheme. Our views on each of these is provided below:

- **Sharing factor** - Ofgem have proposed a reduction of the sharing factor of the scheme to 20%. We do not believe that it is appropriate for this scheme to have a different sharing factor from the main price control as this will influence internal decision-making process to the detriment of consumers. As an example, when considering moving maintenance to avoid a constraint, our exposure to any increased maintenance costs would be calculated using TIM (36.65% in DD) but we would only be exposed to 20% of any additional constraint costs. The decision to change the constraint sharing factor therefore changes the balance between the different considerations and for marginal decisions may result in increased constraint risk being accepted. On the 24th and 31st of July we bilaterally requested further explanation from Ofgem on why two different sharing factors are appropriate and how the 20% value was derived. Ofgem stated that they believed a smaller sharing factor was appropriate and referred back to the consultation documents for the rationale for this. Ofgem have provided the calculations for the sharing factor, collar and cap of the Draft Determination scheme, however whilst these show the maths underpinning these elements of the scheme, it does not provide any reasoning or rationale as to why these are considered to be appropriate.

- **Incentive Target** - Ofgem state that they are not convinced about the robustness and validity of our forecast constraint costs and incentive target. Ofgem's position is underpinned by an AFRY assessment on the analysis undertaken by National Grid both for Network Capability and also for constraint forecasting. Our response to the AFRY assessment of our network capability analysis can be found in section 2.4 of this response. Whilst AFRY conclude that with a different modelling approach and different input assumptions that the resultant forecast of constraints would reduce, AFRY or Ofgem do not offer any quantification of the materiality of this potential reduction or logic as to why this would be a more accurate approach. In response to DD we have undertaken further sensitivity analysis to quantify the impact of increased capability across the network on constraint levels. With a material (5%) increase in capability across the network there is only a limited impact on the constraint risk to be managed during the RIIO-2 period. Further information on this sensitivity analysis is contained in NGGT Annex Network Capability.

  Ofgem have therefore based the RIIO-2 target on RIIO-1 average annual actuals constraint costs. We do not agree with this approach as it doesn't factor in the constraint risk we will need to manage in RIIO-2. For example, [redacted] which is constraint cost risk we managed and therefore should be considered when assessing an appropriate target. Another example is the contracts we have entered into to manage constraint risk [redacted], which is in excess of the Draft Determination proposed target of £200k.

More recently we have entered into contracts with more than one party to manage a customer driven constraint risk. Whilst these costs are paid by the individual customer and are outside of the constraint incentive, they give an indication of the costs of managing constraints. [redacted]

Under such a small target, as proposed by Ofgem, we are unlikely to enter into pre-emptive option contract solutions which we believe, in some circumstances, are the right mitigations for low probability high costs risks, which are ultimately faced by customers and borne by consumers**.** Ofgem / AFRY recognised the need to factor BAU managed risk into the constraint scheme, however they felt that the Network Capability process should take this into account for longer term investment planning and disagreed with our BAU managed risk assessment that we deducted from the constraint target in our proposed scheme.

We disagree that BAU managed risk should be inherent in the longer-term Network Capability assumptions. Availability of BAU operational tools is dependent on prevailing operational circumstances and are therefore not guaranteed to be available at a future date or over a prolonged period. It would therefore be wrong to factor these into long-term decision-making processes.

We also disagree with AFRY that BAU should be based upon historic costs incurred through the scheme as this fails to recognise the purpose of the incentive itself to minimise these costs. For this reason, we proposed using number of scalebacks and operational experience at Milford Haven specifically, as an approximation of constraint days compared to our RIIO-1 forecast. Further information on these points is contained in NGGT Annex Output Delivery Incentives.

- **Cap and Collar -** Ofgem have proposed a narrow cap/collar for the scheme basing this on analysis of the maximum downside and upside financial impacts on NGGT under different plausible scenarios. One consequence of a scheme with a narrow cap/collar is that in the event of a large constraint all of the resulting risk (and cost) is passed onto consumers.

  We have bilaterally requested access to the analysis behind this from Ofgem, Ofgem responded saying they believed a narrower cap and collar range was appropriate. Ofgem have provided the calculations for the cap and collar of the Draft Determination scheme, however whilst these show the maths underpinning these elements of the scheme, it does not provide any reasoning or rationale as to why these are considered to be appropriate.

- **Use of reopeners** – recognising the uncertainty around constraint levels out to 2026, we proposed that the CCM incentive should be subject to a reopener should the incentive cap or collar be reached. Ofgem have rejected the concept of the reopener, saying there is no justification for a reopener; this does not appear consistent with a position where Ofgem believe there is an absence of reliable constraint forecasts. We believe inclusion of reopeners, to at least review any CCM scheme under certain triggers as included in our business plan, should be reinstated as these protect both consumers and ourselves.

- **Removal of Entry Overruns** – we do not support removal of entry overruns from the incentive as this weakens, or even removes, the incentive on shippers to book entry capacity. Further detail on this point and other reasons for retaining entry overruns within the scheme are contained in NGGT Annex Output Delivery Incentives.

In the Network Capability section there are some areas of factual accuracy, where we disagree with Ofgem or where we believe the narrative is misleading. As an example, Ofgem state that NGGT is unlikely to ever have to deliver obligated levels of capacity which in aggregate are in excess of peak demand and therefore an obligation that we are going to have to comply with. In aggregate this is true but critically this misses the point that capacity is sold both on entry and exit as a nodal product and at any individual node, or group of geographically close nodes, there is a realistic possibility that we will have to meet this obligation. In making this statement Ofgem do not appear to appreciate, or indeed have not considered, the implications of a commercial regime that has been deliberately designed based on overselling capacity.

Further information on CCM can be found in the NGGT Annex Output Delivery Incentives, this includes more details on the key points raised above, additional evidence of costs incurred to manage constraints outside of the scheme, factual disagreement with elements of the AFRY report and the Ofgem assessment.

We have also sought external independent assessment of Ofgem's proposals from FTI consulting, their assessment is contained in NGGT Annex FTI Report.

NGGTQ5. Do you agree with our proposals for the Residual Balancing incentive?
Yes, we agree the proposed incentive ensures minimisation of the impact of our residual balancing activities on the market, is challenging and ensures our residual balancing actions are aligned with the interests of stakeholders.

NGGTQ6. Do you agree with our proposals for the GHG emissions incentive?
Yes, we agree the proposed incentive provides additional focus on reducing GHG emissions from compressor venting and will encourage innovation in this space. Working to reduce our emissions is important to customers, stakeholders and consumers and aligns with achieving the government's net zero targets.

NGGTQ7. Do you agree with our proposals for the NTS Shrinkage incentive
Overall, we are disappointed on the lack of clarity of the Draft Determination for the shrinkage incentive. A key reason provided for making the scheme reputational only is that historically a prompt/cashout approach outperformed forward procurement. However, we are unclear as to whether Ofgem proposes for us to leave all/more of our activity to prompt/cashout in RIIO-2. From discussions with Ofgem held on the 31st July 2020 they stated that trading strategy would still be left to us and should be considered as now, which would seem inconsistent with the scheme being made reputational.

We do not agree with the proposed shrinkage incentive being a reputational only scheme. The shrinkage incentive provides value to customers and consumers by providing a focus on managing the risk of price and volume volatility by buying energy efficiently across various time horizons. We have worked hard in RIIO-1 to hedge risk on behalf of consumers around shrinkage price and volume and moving to a reputational only scheme means there will be a reduced focus on our shrinkage activities. This is particularly apparent in the price performance part of the scheme, which does not appear appropriate for a scheme with costs borne by consumers of £50-£90m / year nor is this consistent with the spirit of the RIIO framework. The financial incentive we proposed for RIIO-2 would provide us with us with a sharp focus to challenge and encourage innovation in our hedging/trading strategies. A financial incentive encourages us to keep a sharp focus on adapting to market changes and outperforming an increasingly complex/global market. Without a financial incentive, the provision of shrinkage is more likely to become process driven and would alter the balance of risk as we become less focused on cost targets. This carries inherent risk of increased consumer costs and as a reputational only incentive does not provide focus in the areas described.

Incentive structure

It is not clear how the reputational only incentive would operate and how Ofgem would measure our performance, given that "perfect foresight" and "pure on the day" has not been adequately defined in both the Draft Determination document and in subsequent conversations with Ofgem on the 31st July 2020. However, if "perfect foresight" means the SAP on the day price is not a fair or appropriate benchmark to compare all trades against, this does not take account of price risk/hedging that any organisation managing risk would undertake i.e. it is unlikely that any organisation would leave all trading to on the day as the risks would be too high.

Part of Ofgem's rationale for making this scheme reputational only was based on comparing our trading activity to a prompt and/or cashout approach, we disagree with this and set out our rationale for this below.

Comparing forwards trading with prompt and/or cashout prices is not an appropriate comparison as it does not recognise that this is driven by the risks and durations of the products which drives the prices associated to them. Forward procurement is used to manage price risk. On average across RIIO-1 the forward procurement costs have been higher than on the prompt and/or cashout. The likely level of this premium, timescale and its duration are all product dependent (i.e. quarterly, monthly etc). However, this has not always been the case as in years where prices have risen; then prompt and/or cashout has been more expensive. Also, it is not prudent for any organisation to leave purchasing of all their energy to the prompt market; doing so would expose them to the risk of a rising market and lower probability higher impact events pushing up prompt prices, for example during a scenario comparable to the "Beast from the East". It is therefore prudent to buy energy in the forwards market and be incentivised to hedge the risk of a rising market and extreme prompt and/or cashout prices. In recent years around 70% of our trade volume for gas has been on forwards products for quarters and seasons, and around 30% on "prompt" timescales (predominantly within day, day ahead, weekend).

If Ofgem were to continue to push a comparison to prompt/on the day prices, despite this not being an appropriate comparison, this suggests that Ofgem propose leaving shrinkage procurement to prompt is the most efficient and economic thing to do for consumers. This would mean whilst we would retain some forward volumes, we may be more likely to procure a greater proportion of shrinkage volume in prompt timescales. Whilst over a number of years and in the long term this may result in a net saving, this would create greater exposure of price shocks to our customers and consumers in the event of high prompt prices occurring.

Ofgem note AFRY estimate the value at risk for shrinkage to be approximately £10-20m but that this might only materialise in rare circumstances. However, these circumstances do occur. If left to cashout the cost of shrinkage from the "Beast from the East" would have been £9m. The actual cost was £1.1m, saving NTS users, and ultimately consumers, £8m in one day alone. With the weather becoming increasing unpredictable such events may become more likely.

It is also worth noting that in specific years where the market has risen that forwards have outperformed prompt. Market prices are at historic low levels, so there is strong potential for upward pressure on gas market prices, leading to forward trading to be more economical than leaving to prompt procurement. This is quantitively illustrated within the Draft Determination Incentive Annex. For example, in 2016/17, Gas procurement cost (all forward trades, prompt trades and cashout) was £49.7m. Actual shrinkage costed at daily SAP was £52.0m and cashing out this would have cost £54.0m.

Procurement of electricity volumes

Throughout the Draft Determination position on shrinkage the trading of electricity has not been considered within Ofgem's rationale. Whilst we can trade both forwards and prompt for gas, this is not the case for electricity, which accounted for 17% of our trades in the last four years. We anticipate VSD (electrical compressors) usage to increase over the RIIO-2 period. As we are not able to trade directly on the electricity market we are required to contract with a third party to undertake this trade on our behalf which means we are currently restricted under that contract to trade electricity up to D+2. Remaining electricity requirements are left to cashout prices on the day. Therefore, the benchmark of on the day trades is not appropriate for electricity trading. Ofgem have not indicated how they intend to measure performance of electricity volume purchases given we are unable to trade on the day contracts, so it would not be appropriate to use these prices as a benchmark.

Shrinkage methodology
Ofgem's Draft Determinations leaves the proposed shrinkage methodology unclear. However, we currently believe it is necessary to transparently set out how volumes are calculated to be purchased against and we anticipate continuing to publish a slimmed-down version of the methodology to make this transparent to the market.

Proposal to regularly investigate the causes of UAG and CVS and to improve on metering/inspection activities
We are disappointed that further information about what this apparent change in policy would entail is not included within the Draft Determinations, and in the absence of that detail, we do not agree with a new obligation as we believe the current licence condition remains fit for purpose and encourages the right behaviour.

We would also note that we do not own the majority of meters so are not best placed to address metering errors leading to UAG. From a perspective of calculation of shrinkage, over 90% of measurements that form part of this calculation are from equipment owned by distribution networks. Therefore, responsibility for addressing metering issues does not fall solely to NGGT.

Further information on our views on the proposed shrinkage incentive can be found in supporting Annex (NGGT Annex Output Delivery Incentives).

<u>Bespoke ODIs</u>
NGGTQ8. Do you agree with our proposals on the bespoke ODIs? If no, please outline why.
Please see Question 9 for our response in relation to the proposed Environmental Incentive. We accept the proposals for the other bespoke (as defined by Ofgem) ODIs.

We note that Ofgem have, erroneously set out in Table 8 of their DD NGGT Annex a number of our commitments that were not proposed specifically as a reputational ODI in our December business plan.

- Operating Margins
- Unaccounted for gas (UAG)
- Data provision
- Business Carbon Footprint (BCF) reporting. The latter was proposed as a Licence Obligation which has been taken forward as a Licence Obligation by Ofgem.

NGGTQ9. Do you agree with our proposals for the Environmental incentive?
We welcome Ofgem's acceptance of the consumer benefit of an environmental incentive, and that they accept the basic design of our ODI-F.

However, Ofgem is proposing a number of changes to the NGGT environmental scorecard ODI-F in its DD. We give our view on each change below.

First, Ofgem is proposing splitting our scorecard ODI into seven mini-ODIs in its Draft Determinations. We prefer a scorecard ODI as it provides one, relatively large, incentive rate to focus the minds of NGGT and stakeholders on the importance of delivering the EAP. Seven mini-

ODIs with smaller incentive rates might not provide the same focus. The environmental scorecard ODI avoids having to calculate incentive rates for each of the seven metrics and provides a broadly right overall value for delivering the EAP. Ofgem raises a concern about the size of the incentive rate in paragraph 2.123, but they could preserve the scorecard nature of the ODI and adjust the overall incentive rate.

Second, Ofgem says that if they accept the scorecard nature of the ODI they will reduce the weighting of “Percentage of our operational and office waste”, “Percentage reduction in the waste we create at our offices” and “Percentage reduction in water use for our main offices” to a third of the other four metrics (paragraph 2.122). We proposed a simple approach of an equal weight for all 7 metrics in our scorecard ODI, but we can accept Ofgem’s proposed reweighting if they continue with a scorecard approach.

Third, Ofgem is proposing to change the incentive rate to create the seven mini-ODIs and is consulting on two options: the economic value of the environmental benefit; or the abatement cost plus a margin (paragraph 2.124). We set out our proposed approach below. We prefer the environmental benefit over the abatement cost wherever possible because this means the incentive rate more closely reflects the actual benefits our actions are delivering.

Table NGGT10 – Proposed approach to EAP incentive rates

No.	Metric name	Proposed approach to the incentive rate
1	Vehicle fleet emissions	1. use the non-traded value of carbon (source: Treasury Green Book) 2. we could add in other benefits such as the air quality damage costs in NOx and PMs (source: DEFRA Air quality guidance damage costs appraisal)
2	Percentage reduction in carbon emissions from business transport mileage	
3	Percentage of our operational and office waste that is recycled	1. use emissions factors to calculate GHG emissions differences between landfill and recycling (source: DEFRA 2019 emissions factors kg/CO2e). 2. we will be engaging with waste and resource companies to assess a whole-life social value, including emissions from travel and land-use
4	Percentage reduction in the waste we create at our offices	1. use the non-traded value of carbon (source: Treasury Green Book) 2. we will be engaging with waste and resource companies to assess a whole-life social value, including emissions from travel and land-use
5	Percentage reduction in water use for our main offices	We will be engaging with water companies to assess a robust social value in reduction in water, including electricity used for treatment of water and treatment of wastewater
6	Percentage increase in the environmental value of our non-operational land	We proposed to base this incentive rate on our sector-leading natural capital tool and proposed Consumer Value Proposition figures.
7	Percentage increase in environmental value on all major construction projects	We have a meeting with SHE-T and Ofgem on 7th September to discuss aligning valuation methodology with SHE-Ts CVP methodology, so we will provide a methodology for calculating the social value of net gain after these discussions.

Finally, the metric around percentage increase in environmental value on major construction projects may not be measurable in all years given the timings of major construction project delivery. This element of the incentive should be drafted within the licence to enable it to be “turned off” in years without major construction projects.

Re-specifying metric for alternative fuel vehicles

We do not believe re-specifying the metric for alternative fuel vehicles as a reduction target for CO2 emissions from operational transport compared to 2018/19 levels is an appropriate approach for NGGT. This is because our operational vehicle fleet increases into the RIIO-2 period, predominantly due to an efficiency programme that moved operational resources out of company cars into our operational fleet, but also because of additional vehicles associated with specific work programmes such as cyber resulting in additional fleet vehicles support to carry out our operations. Our emissions therefore will be higher than the 18/19 benchmark year in the early years of RIIO-2.

However, we recognise that Ofgem's intention with this request to measure the CO2 impact of the activity. Therefore, we propose, re-specifying the metric as tonnes of CO2 equivalent for annual operational fleet emissions in RIIO-2.

To calculate these metrics, we created an expected profile for emissions over RIIO-2, taking into account the number of vehicles in each year and reducing emissions where alternative fuel vehicles are planned. This is built on assumptions around average mileages and emissions per type of vehicle. To create the upper and lower bounds we have then proposed 10% either side as the penalty and reward level. These are as follows:

Table NGGT11 - proposed vehicle ODI metrics

	Metric (tonnes of CO2 equivalent)*	Penalty level	RIIO-2 target	Reward level
1	Annual operational fleet emissions in RIIO-2	1880	1709	1538
2	Annual operational fleet emissions in RIIO-2	1846	1679	1511
3	Annual operational fleet emissions in RIIO-2	1799	1636	1472
4	Annual operational fleet emissions in RIIO-2	1610	1464	1317
5	Annual operational fleet emissions in RIIO-2	1380	1255	1129

NGGTQ10. Do you agree with our proposals for the proposed Stakeholder Satisfaction incentive?

Yes, we agree with Ofgem's proposals for the stakeholder satisfaction incentive, acknowledging the expectation to publish the results of the stakeholder satisfaction surveys annually as part of our annual reporting.

PCDs

NGGTQ11. Do you agree with our proposals on the PCDs? If no, please outline why.

Coverage of the plan

We support the concept of Price control deliverables, a new type of output for RIIO-2, as a means to hold network companies to account. As a result, just under half our plan (47%) is subject to Price control deliverables, with Ofgem's proposals covering the same broad areas as we proposed within our December business plan. However, we have serious concerns with the content (or lack thereof) within the Draft Determinations with regards to the PCD framework.

Lack of consultation on PCD guidance

Ofgem has not provided us sufficient information to fully understand the impact of the implementation of this new type of output for RIIO-2 as part of the Draft Determinations.

In terms of the information presented within the Draft Determinations itself, the text in paragraphs 4.8 to 4.10 of the core document on the PCD framework is very limited and only: refers back to what the SSMD says about setting PCDs for certain types of projects; says that PCDs are by their nature relatively bespoke and the ways in which they are set and assessed will vary accordingly; and refers to specific PCDs within the relevant Draft Determination document (typically company annexes), which themselves provide limited information that will be clarified through licence and guidance documents.

Instead of including it in its Draft Determinations, Ofgem proposed elements of its PCD policy framework at a workshop on 18 August 2020, six weeks into the eight-week consultation period. Furthermore, Ofgem only shared a draft of its PCD framework paper on 27 August at the end of the seventh week of an eight-week consultation, and has only given network companies a narrow period of consultation time in which to respond. This paper appears on a first reading not to address the issues we have identified below.

Ofgem has not allowed network companies a full opportunity to comment on Ofgem's PCD framework as part of its Draft Determination because the PCD framework is still clearly subject to large amounts of development after the Draft Determinations have been issued.

We recognise that in Ofgem's proposed licence text that Ofgem would have to formally issue a 28-day consultation on any PCD guidance. However, in order to reach a view on the PCD framework, we expect Ofgem to fully consult on the guidance with stakeholders ahead of this to ensure the impact on the industry and network companies price controls is fully understood and considered.

Lack of clarity on penalties relating to PCD delivery

We recognise the intention of PCDs is to hold us to account where an output is not delivered. We agree with this and proposed within our business plan that where an output is not delivered because that is in the interests of consumers, that funding for the output, less any costs should be returned including WACC.

Whilst Ofgem's draft policy framework set out more detail than that available in the Draft Determinations, we believe that the proposals provide Ofgem with an inappropriate amount of scope regarding penalties relating to PCD delivery. Whilst in the text of the policy framework the parameters for adjustments for delivery adjustment appear discrete e.g. reprofiling allowances for late delivery, Ofgem also appear to be at the same time proposing a broad ex-post assessment mechanism (paragraph 7.5). At a principle level, an ex-post efficiency assessment is not in the interests of consumers. It increases regulatory risk arising from the danger of second guessing our actions against perfect hindsight and would be resource intensive across network companies, Ofgem and our stakeholders (who will need to contribute and who's input will be critical to ensure decisions give them what they need). It has the potential to stifle valued innovation, weakening incentives for efficiency and slowing productivity. Subjecting large sums of baseline funding to the threat of clawback also potentially undermines investor confidence with a potential impact on financeability. All of these things will generate bad outcomes for customers, delaying work, higher costs and less innovation, at a time when agility and flexibility is critical.

For the first time at the 18 August 2020 PCD workshop, on slide 8, Ofgem raised the potential for:

1. adjustment to allowances that go beyond recovering allowances for the part of outputs that have not been delivered; and
2. adjustment to allowances that ensure consumers do not suffer any detriment.

This was not included in the Draft Determinations or the PCD draft policy paper. However, should this arise as a formal Ofgem policy it would be extremely concerning. It opens up the possibility of potentially very large and uncertain penalties for not fully delivering a PCD output because consumer detriment is hard to measure, is often not knowable in advance and affected by factors that a network company cannot control (e.g. constraint costs caused late delivery can vary hugely depending on the weather and the generation market).

We also do not support claw back of allowances where projects are delivered late, if this is not in the network companies' control. Ofgem have set out that they Companies would likely already be incurring significant costs if a project were delayed. Also, many of our PCDs are already covered by other licence obligations, or legislation, for example environmental legislation. As such, a double penalty for non or late delivery would be inappropriate and not in the interests of consumers.

As a result, we believe Ofgem should take account of the potential issues around penalties when developing its final views. Ofgem should formally consult on its approach to PCD penalties in September.

Lack of clarity on revenue arrangements
Ofgem has not been clear when the revenue changes resulting from Ofgem assessment of PCDs will take effect.

At its 18 August 2020 PCDs workshop Ofgem provided, for the first time, information on when it might make adjustments to network companies' allowances for PCD delivery. Ofgem said it was considering making adjustments at RIIO-2 close out; or with one or two mid-period review as well as RIIO-2 close out for PCD delivery. Ofgem needs to provide firmer proposals to network companies so that they can understand the risks to their financial profiles in the RIIO-2 period, and this should be consulted on at the earliest opportunity.

Status of PCD guidance
Notwithstanding the lack of consultation and clarity set out above we have serious concerns about the status of the PCD guidance itself. Ofgem must make sure that the rules for outputs with such a huge coverage across the plan are written robustly into the licence rather than relying on guidance that Ofgem can change without protections for network companies.

Given Ofgem's policy as we have described above of potentially large and uncertain penalties related to consumer detriment for not fully delivering a PCD output and Ofgem's policy of reviewing a network company's delivery ex post it is absolutely vital that the licence sets out clearly:

- A precise definition of the PCD output
- A precise definition of what constitutes non, late and partial delivery
- An explanation of what constitutes acceptable equivalent delivery for Ofgem.
- The financial consequences of non, late and partial delivery
- The process and timing of the recovery of any allowances for non, late and partial delivery

Our comments on specific PCDs over and above the issues raised above are set out as follows. (where this relates to specific consultation questions this is identified)

Major projects PCDs
Projects: compressor investments, Bacton Terminal Redevelopment, King's Lynn subsidence
We believe careful consideration needs to be given to how delivery is measured for these projects and at what point. This is project specific and should be set out within the licence.

Decommissioning PCDs (NGGTQ28)
The decommissioning portfolio of projects anticipated for RIIO-2 is broad, and there are already new customer-driven disconnections that have been identified since the submission of our business plan. The decommissioning PCD should define equivalent delivery in such a way that NG can prioritise new projects for decommissioning based on risk within the price control period, as set out in our December plan proposal to ensure that customer money is being spent addressing the assets that pose a higher risk.

Asset health – non-lead assets (NGGTQ25)
We are comfortable with the approach that Ofgem has taken to the PCD on asset health – non-lead assets.

Physical resilience PCDs (NGGTQ30)
We support Ofgem's proposal that the Physical Security PCD will only apply to capex activity for PSUP upgrades at new sites.

Cyber PCDs (CoreQ17)

We agree that the PCD should include alongside the delivery of project-specific outputs the delivery of outputs such as CAF outcome improvement, risk reduction and cyber maturity improvement as this is consistent with our December 2019 business plan.

NARMs - please see specific NARMS responses NARMQ1-Q4.

Licence obligations

Network Capability

Answers to the specific consultation questions are provided below, however there are a number of points on network Capability that we wish to make in response to Ofgem's conclusions on Network Capability and the AFRY Report on Network Capability.

Ofgem's conclusions on the robustness of the outcomes from our Network Capability analysis appear to be solely based upon the analysis undertaken by AFRY, with no apparent overlay from Ofgem to reflect their own assessment or substantiate the position taken within DD. AFRY acknowledge that "the principles of the methodology appear sound" and that "the construction and collation of the various documents and process has significantly improved the transparency of what is a very complicated area".

AFRY do highlight that the results are heavily dependent on the underlying assumptions used in the analysis, a point that we agree with. AFRY conclude that the assumptions "are **perhaps** extreme and therefore in many circumstances **may** understate network capability". These statements are unquantified yet appear to have heavily influenced the position taken by Ofgem in DD without robust justification.

We do not agree that assumptions we have used are extreme. In contrast, the assumptions are in fact aligned with the existing Transmission Planning Code (TPC), the content of which is consulted upon and approved by Ofgem every two years. Most of these assumptions in question relate to exit from the network where we have specific safety and other obligations, such as the 1 in 20 (Pipeline Security Standard) license condition. We have an obligation to ensure our network meets the 1 in 20 standard, thus using agreed assumptions that underpin our ability to demonstrate how we meet these obligations should not be classed as extreme, indeed this is what customers and regulators require of us.

AFRY highlight that "NGG has presented no information on why they chose the approach/assumptions they have beyond it being consistent with the TPC approach". As TPC is consulted upon with industry we fail to see how this could not be considered the right approach, indeed had we deviated away from TPC that would not be justified. Further information on our response to AFRY's comments on the assumptions used in our analysis can be found in supporting Annex (NGGT Annex Network Capability). FTI have also provided an independent view on AFRY's comments on Network Capability (NGGT Annex FTI Report).

Notwithstanding the above points on AFRY's assessment of Network Capability, we would also highlight that these assumptions have limited impact on the level of forecast constraints at entry points, which are the focus of our constraint forecasts.

The AFRY report does not provide any quantification of assumptions being "perhaps" extreme or that we "may" have understated network capability, other than comparing our RIIO-2 forecasts with RIIO-1 actuals, which is not a robust comparison for an area which historically has been viewed as a low probability of occurring. Further detail on the actions we have taken in response to RIIO-1 constraint risk can be found in the answer to Question 4. AFRY also state that they cannot say whether the assumptions have "a material impact on the Network Capability assessment". This comment is linked to a comment that "Despite information on the magnitude of relaxing this assumption being requested from NGG we have received no information". It was not possible to produce all requested analysis in the time available as this would have taken months to complete.

This was discussed with AFRY and in their report, they recognised that a "number of aspects of the process are resource intensive making iterative recalibration difficult". We did however answer written SQ's and two sets of follow up questions from AFRY on the assumptions used. Following these discussions AFRY stated on an email, 13th March to NGGT, "I think we have enough information to finish our report to Ofgem"; we do not believe this is consistent with a comment about receiving no information from NGGT. In response to DD we have undertaken further sensitivity analysis to quantify the impact of increased capability across the network on constraint levels. With a material (5%) increase in capability across the network there is only a limited impact on the constraint risk to be managed during the RIIO-2 period. Further information on this sensitivity analysis is contained in NGGT Annex Network Capability.

Despite requests from us to Ofgem to share the AFRY report and/or the conclusions ahead of publication of Draft Determination, Ofgem choose to only share the Exec Summary of the report. Given the report is dated 3rd April, it is disappointing that ~3 months have been lost, in which time the sensitivity analysis could have been undertaken to identify whether AFRY concerns over assumptions are in fact material or not. It is not clear why Ofgem made the decision not to share the report or request this analysis given their stated low confidence in the assessment of physical capability of the NTS in the Draft Determination.

NGGTQ12. Do you agree with our proposals for LO in relation to NCAM and ANCAR?
We are supportive of the principles of both the NCAM and ANCAR, although would highlight that further detail is required to fully scope the required processes, documents and timing of these.

We would highlight the requirement to report on "the level of Network Capability that can be delivered using commercial tools for each of these Entry and Exit Zones" as an area requiring further clarity. Theoretically, at a high enough price, we could contract for commercial tools with all entry and exit parties in a zone. However, we do not believe this would be economically rationale or reflective of reality. More clarity is therefore required on the basis which any assessment of the availability of commercial tools should be made.

NGGTQ13. Do you agree with our proposal not to set network capability targets for RIIO2?
We agree with the proposal to not set network capability targets. On a point of clarity and in response to paragraph 2.146, we would like to clarify that whilst the proposed decommissioning of compressor stations during RIIO-2 will not change the level of network capability it will reduce the amount of time that any specific level of network capability could be delivered (i.e. resilience will reduce).

The proposed level of asset health spend in our Business Plan was designed to ensure that the level of network risk remained the same at the end of the RIIO-2 period as it is at the start. With reducing numbers of compressors on the network, it is important that we maintain the remaining compressors, and other assets, at the right intervals to ensure we retain the required levels of availability and reliability. This is essential to ensure we have the necessary levels of resilience to accommodate planned and unplanned outages, minimising the impact on our customer's ability to put gas onto and take gas off the network. Ofgem's proposed reductions in Asset Health expenditure in RIIO-2 will have a detrimental impact on level of network risk.

Whilst absolute "maximum" level of network capability is maintained through RIIO-2, reducing resilience, coupled with Ofgem's proposed reduction in Asset Health expenditure, means lower resilience and increased likelihood of constraints that would need to be managed as part of the CCM incentive scheme.

NGGTQ14. Do you agree with the proposal to reduce entry baseline capacity at St Fergus?
We support the proposal, which aligns with the conclusions we reached following consultation with our stakeholders and included in our Business Plan Annex A12.03 Baseline Obligated Capacities Report.

NGGTQ15. Do you agree with the proposal to reduce entry baseline capacity at Theddlethorpe?
We support the proposal, which aligns with the conclusions we reached following consultation with our stakeholders and included in our Business Plan Annex A12.03 Baseline Obligated Capacities Report.

<u>Consumer Value Propositions</u>

NGGTQ16. Do you agree with our proposals on the CVPs? If no, please outline why.
We support the principle of the CVP driving additional value for consumers. CVPs help show the enhanced value our plan provides for consumers. It fits well with our increased emphasis on engagement and openness in our RIIO-2 business plan. We note that the CVP is only a small part of the consumer benefit of our business plan. However, we have concerns over the CVP approach in context of the wider BPI, the size of the rewards across the industry compared to the size of penalties is small, with rewards still being subject to burdensome reporting requirements. The incentives this creates is for companies to avoid being innovative in future (clearly no rewards available for this) and simply focus on keeping costs down which does not support the principle of driving additional value for consumers. We would request Ofgem to reconsider their CVP proposals.

We note that CVPs are a new concept introduced for RIIO-2. It was challenging to identify what should be put forward for CVP and the approach to robustly quantifying this. This is reflected in the fact that across networks 117 CVPs were proposed and only 6 have (or would have subject to BPI stage 1 outcome) merited award. The scale of disallowed propositions demonstrates that the scope, approach and assessment criteria and therefore Ofgem's level of guidance on CVP was unacceptable. This has resulted in a flawed, asymmetric business plan incentive with limited opportunity to reward network companies for the parts of our plans which drive consumer value beyond that which could be expected of us.

We used external experts to independently assess what elements of our plan drive additional value to consumers and the robustness of potential methodologies. We also engaged with the independent User Group and key consumer stakeholders to gain vital feedback on our CVP propositions. Our approach was only to submit those CVPs for which we were:

- confident in the robustness of the methodology,
- received stakeholder support,
- clearly demonstrated above minimum value.

This resulted in an initial long list of CVPs not being progressed. It also resulted in the inclusion of commentary on 3 CVPs where we could provide an order of magnitude estimate, but not a firm methodology (one of our stakeholders requested that this be included). These were not put forward as part of our CVP proposition, but we note that Ofgem assessed and subsequently rejected these.

<u>Reporting requirement:</u>
We agree with the importance of reporting annually, and a more detailed close out summary. A common template covering status/commentary is sensible, aligned to specific metrics for individual CVPs. As part of our CVPs we proposed that the independent User Group would be a sensible body to provide a report to and are pleased that Ofgem is supportive of this approach.

<u>Performance metrics:</u>
We agree with the need to produce metrics to ensure output is measurable. Of the 2 CVPs which were identified by Ofgem as meriting CVPs:

- Communities we have proposed specific metrics for (see NGGTQ19).
- For Natural Capital Improvements, in line with Ofgem's desire to provide a consistent methodology for this CVP we are working with Ofgem to define metrics for this (see NGGTQ17).

We agree there should be no monitoring of CVP proposals that were rejected.

We set out here our response regarding the 6 CVPs that Ofgem rejected, noting that only 3 of them were submitted as formal CVPs.

Table NGGT12 - CVP position on rejection

CVP	Our position on rejection
Resilience solution at Blackrod	We note that this CVP was rejected on the basis that the associated investment was rejected. It would be helpful to understand Ofgem's position on this as a CVP in its' own right so that we could provide meaningful commentary. We do not agree with Ofgem's proposal to reject the proposed Blackrod Reinforcement project. We continue to believe that baseline funding should be approved to provide additional resilience and security of supply [redacted] and provide evidence for this in response to NGGTQ20. Once baseline funding has been restored for this, we welcome the opportunity to engage with Ofgem on the appropriate approach to this CVP which continues to merit reward. The work that we are planning to carry out during RIIO-2 at Blackrod, to increase network resilience, is an example of where we have gone beyond business as usual to find the optimal whole system solution to a problem. The default option (our counterfactual scenario) would be to consider the issue in isolation, not build the new pipeline, and to leave the risk of a local supply interruption at current levels. By engaging closely with Cadent (the GDN connected at Blackrod), we found a cost-effective solution to address the risk of supply interruptions. This work established that solutions on the transmission system were cheaper than solutions on the Cadent distribution network. The consumer benefit of this activity would be realised upon project completion. Metrics to track delivery, would therefore be aligned to reporting on project delivery. And should we fail to deliver the work, then appropriate clawback would be to pay back the CVP allowance.
Security Innovation application	We note this was rejected as it has not been demonstrated to go sufficiently beyond BAU. In submitting our CVP we noted the interaction with the Network Innovation Allowance funding used to develop this solution, and the need to consider how this should be reflected in rolling out in RIIO-2.
Business carbon footprint reduction: construction	We note this was rejected on the basis that reducing business carbon footprint should be a BAU ambition. We agree that some reduction of business carbon footprint could be considered BAU. However, our commitment goes beyond BAU as it is to be carbon neutral (not just deliver a reduction). This will be achieved through a combination of carbon neutral targeted activities and offsetting any residual. We would note the feedback from Citizens Advice to support this "*Whilst there could be an argument we do not need to pursue carbon neutrality until later, given this proposal responds to stakeholder and consumer feedback we should be rewarded for going beyond baseline expectations."* We note that other network companies (for example NGET) have had funding approved to offset emissions that cannot be eliminated technically or cost efficiently. We have requested no funding for our commitment (it will be shareholder funded). It would appear perverse to provide upfront funding for offsetting, yet not recognise this ambitious commitment through a CVP.
Facilitate connection of smaller gas suppliers	This was not submitted as a formal CVP, rather an order of magnitude estimate. We note the interaction with innovation funded through NIC and are fully committed to implementing these improvements.
Whole system strategy	This was not submitted as a formal CVP, rather an order of magnitude estimate. We welcome Ofgem's recognition of our ambition to take a leading role in the decarbonisation of heat.
Methane emissions reduction	This was not submitted as a formal CVP, rather an order of magnitude estimate. We note it was rejected on the basis that it does not go beyond BAU and would confirm this is a key activity we will undertake during RIIO-2.

NGGTQ17. Do you agree with our consultation position to allow (subject to eligibility under the BPI) the natural environment improvements CVP?

We are pleased that the natural environment CVP has been recognised as going beyond BAU and providing demonstrable consumer value.

There is no requirement for us to improve the natural environment on our land, and in a counterfactual scenario we could do nothing with our estate and would not deliver any benefits. However, we have been working towards measuring the natural capital and biodiversity value of our non-operational land and have set a target to improve this by 10% over RIIO-2. This will bring benefits to both the natural environment and to communities that can use this land. Because these types of natural capital improvements are relatively low-cost, the consumer benefits far outweigh the costs.

We note that in order to maintain existing natural capital value requires significant work and, therefore, 10% is a stretching commitment. We would also confirm that our intent is to enhance against at portfolio baseline figure from across all of our sites. This can be achieved by enhancement of sites where opportunity is the greatest and can deliver the greatest value, rather than every single site.

Where, by the end of RIIO-2, we increase the value by less than 10% we agree that a proportional payback of any CVP awarded is appropriate. We are working with Ofgem and NGET to agree the best approach to measuring natural capital for this CVP based on National Grid’s existing tool. Appropriate metrics will be developed as part of this work.

NGGTQ18. Do you agree with our proposal to re-quantify the value of the CVP?
Our Natural Capital Tool provides indicative and theoretical value, not an exact monetary value that consumers will get. Whilst we believe it provides a robust framework on which to set a baseline for improvement, it is a decision support tool not an accounting tool. We note the challenge of identifying a specific value and the desire for consistency across the 2 similar CVPs (NGET, SHET).

We are working with Ofgem and NGET to define an appropriate methodology that can be applied consistently.

NGGTQ19. Do you agree with our consultation position to accept (subject to eligibility under the BPI) the community initiatives CVP?
We are going beyond minimum requirements by committing to spend on community initiatives. We are not requesting additional funding to cover this spending. By committing this money to local community initiatives, we are ensuring that local communities’ benefit, and money is allocated to areas valued by local communities. We are pleased Ofgem recognised that communities affected by our construction will benefit from localised community projects, and our commitment to spend 0.3% of total project costs on these initiatives goes sufficiently beyond BAU.

We note other companies proposed similar CVPs using a social return on investment multiplier. One of the key principles in our approach to CVPs was to ensure the methodologies focused on the minimum level of value (when in reality the consumer value is likely to be much higher). We referenced a study carried out by Auriga for Severn Trent Water, United Utilities and Thames water found that every £1 invested by the water companies in social schemes delivered £3.06 of benefit. However, we chose not to apply a similar multiplier as the initiatives covered in the study may not be comparable.

Based on our associated major project spend, in our business plan we proposed to spend £0.6m on community initiatives during RIIO-2. This would result in a CVP reward of £0.22m (based on the sharing factor in the Draft Determination). A suitable clawback mechanism would be to pay back the relevant proportion of the CVP reward. It would not be suitable to pay back any unspent amount of the £0.6m commitment (as appears to be currently worded in the Draft Determination).

The community initiative pledged within our business plan was £0.6m based on 0.3% of total major project costs (those valued above £50m). The value of major projects in our December business plan on which this CVP was based was £221.5m (£78.5m Wormington compressor and £143m Bacton). Given the full project costs for all major projects has been moved to part of the reopener uncertainty mechanism process, there are currently no new RIIO-2 projects within the Draft

Determination which have more than £50m in the baseline. However, we believe the CVP value remains valid given:
(a) the reopener uncertainty mechanism design should see these projects progress during the RIIO-2 period, and we are still committed to the pledge of spending 0.3% of total project costs on community initiatives,
(b) the clawback mechanism will ensure that should we underspend on community initiatives any corresponding CVP allowance is paid back, and
(c) should reopeners be successful, the number of major projects should increase beyond that in our December business plan throughout RIIO-2, leading to us spending more on community initiatives.

Metrics:
We will report annually (and cumulatively) on what we have spent on community initiatives associated with major projects for projects where we have full allowances agreed that enable us to proceed to the build phase. We will also include a final view on the metric at closeout.

Following the final reopener where the PCD and allowance are set, we will report annually on spend on community initiatives for each identified major project. These metrics will cover:
(a) total spend on project;
(b) £ and % of total project spend on community initiatives;
(c) what the spending was on.
This will allow a clear identification of what proportion of the reward has been delivered. This reporting can be used with Ofgem and the independent User Group to track and monitor progress.

3. Cost of service - setting baseline allowances

Load-related capex

Table NGGT13 – Network capability costs

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	11.59	2.74	11.59
Efficiency	0.00	-0.13	0.00
Capitalised Opex adjustment	0.00	-0.30	0.00
Total	**11.59**	**2.31**	**11.59**

NGGTQ20. Do you agree with our proposal to reject the Blackrod Reinforcement project?
We do not agree with Ofgem's proposal to reject the proposed Blackrod Reinforcement project. We continue to believe that baseline funding should be approved to provide additional resilience and security of supply to [redacted] gas consumers.

Based on comments in the consultation document, we are concerned that there is a misunderstanding over the need case for the proposed pipeline. The proposal was not made based on historic outages on the existing pipeline and whilst in favourable circumstances NGGT, working with Cadent, could accommodate planned or unplanned outages, there are circumstances where outages would impact supply to consumers.

With any pipeline there is an inherent risk of failure or other event that reduces its operational capability (e.g. a result of a safety requirement to reduce pressure following discovery of a defect or as a result of 3rd party damage). From this perspective, this pipeline is no more or less risky than other NTS pipelines of a similar age. The reason for our proposed investment at Blackrod was because during high demand it alone provides security of supply to [redacted] consumers and resilience can be easily provided by connecting two existing pipelines that are only ~1km apart.

On the above basis alone, we would have proposed construction of the resilience pipeline.

There is a slight additional risk, specific to the existing pipeline to Blackrod, as it passes through Heapey Dam. The owners of the dam have received an improvement notice to carry out upgrades to ensure the dam can withstand a 1:1000 to 1:10,000 flood event; it is currently rated to withstand a 1:100 flood event. This creates an additional risk to the pipeline and correspondingly to provision of gas to consumers, however this investment would be in the interest of consumers even without the risk presented by the dam.

In the event of pipeline failure or other restriction impacting its capability, the consequences are considerable in terms of the potential number of impacted customers both domestic and commercial. It would take weeks (or even months) to reconnect them, with associated costs and a significant risk to life as loss of supply is more likely to occur during a period of cold weather when demand is too high to be accommodated via the distribution network.

We provided an EJP and CBA for this project which showed that the project remained cost beneficial even with a risk of pipeline failure of 1 in 2000 years and assuming a two-week period that consumers were not supplied with gas. This two-week period is extremely optimistic given the time it would take to reconnect a large number of consumers safely, and in the event of a catastrophic failure, the time a significant repair would require.

This type of investment would not normally require a QRA as it passed an initial CBA which explained robustly the investment and benefits. The work was relatively low cost and the benefit to consumers were clear, therefore this CBA was sufficient.

Ofgem have confirmed that provision of a Quantitative Risk Assessment (QRA) would better help them understand the need case for this project. Alongside this response we are providing a QRA document, supported by a QRA Excel file.

The conclusion of this QRA is that we strongly believe that the proposed investment is in the interest of consumers as it would provide resilience for gas supply to the [redacted], whilst providing additional benefits such as being able to better manage pressure reductions and carry out maintenance. We have demonstrated the significant consequences that would result, costing upwards of [redacted]. Throughout the QRA we have tended towards the lowest reasonable values and therefore it is likely that the actual probability and impact of a loss of supply would be higher than those assumed within our calculations. The QRA also excludes the risk presented by the section of pipeline running through Heapey Dam which could not be quantified with the data available at this time, again resulting in a lower assumed risk than is really the case.

In the consultation document, Ofgem highlight the cost uncertainty around this project, which was stated as +/- 30-70% at the time of the December 2019 Business Plan. This value being standard for a project at stage 4.0 of our investment planning process (i.e. early in our planning process). For a diversion type project, we would expect the cost certainty to be at the narrower end of this range (+/-30%). That is because this pipeline project has a much greater scope maturity than usual for this stage and the cost range will lower but cannot be formally narrowed without progressing further through our network development process, and hence the wider range was included in our Business Plan. The reasons for confidence in a narrower cost range are:

- Limited scope variation in pre-defined solution (approximately 1.1km of 900mm pipeline, AGI and connections).
- Recent, similar and multiple projects used to generate unit costs for this estimate.

Ofgem also highlight that the low materiality overall makes the project a poor candidate for its own UM. On a wider point, we would welcome clarity from Ofgem on how projects that are of too low a level of materiality to warrant their own uncertainty mechanisms should be developed to a level of cost certainty that is acceptable to Ofgem. For major projects, Ofgem are proposing RIIO-2 funding to reach an appropriate level of cost certainty, with no equivalent mechanism in place for smaller projects.

Having rejected this project in their Draft Determination, Ofgem also use this rejection as one of the reasons for application of a Stage 1 penalty under the BPI arrangements. Even if Ofgem reject the proposed pipeline at Blackrod in their Final Determination, we do not believe that this stakeholder-supported proposal should be a reason for application of a Stage 1 BPI penalty; further information on our response on BPI can be found in NGGT Annex Business Plan Incentive. From discussions with the Ofgem engineering team we understand that they also do not support Blackrod as a reason to apply a BPI Stage 1 penalty.

Ofgem should reconsider the treatment of the Blackrod investment under BPI stages 1, 2 and 3. in their Final Determination. Please see NGGTQ16 and NGGT Annex Business Plan Incentive for more detailed responses on CVP and BPI.

NGGTQ21. Do you agree with our proposed allowances for LRE?

Load Related Expenditure is made up of a number of separate elements. Our view on the proposed allowances for each of the elements is set out in turn:

- **Entry** - We agree with the incremental capacity UM to deal with uncertain costs. Development work on the customer driven application for increased capacity at Milford Haven has continued since the time of our business plan submission.
- **Exit -** We disagree with Draft Determination Table 14, page 62, exit row, right hand column which says: Ofgem proposed UM "no". This box should say "yes" - the incremental capacity UM reopener should apply to both entry and exit.
- **Network Capability:**
  - o Blackrod: Please see our separate response to NGGTQ20.
  - o Changing customer needs: We agree with the proposed baseline allowance of £1.73m.
  - o Tactical Access (Tirley AGI): We agree with the proposed baseline allowance of £1.0m. This remains an important project to reduce constraints risks at the Milford Haven terminal.
  - o Offtakes: We agree with the proposed allowances
  - o Capitalised opex adjustment: Following engagement with Ofgem through the consultation process Ofgem agreed that capitalised opex adjustments totalling £77m had been incorrectly applied to net capex costs rather than costs inclusive of capitalized labour; effectively resulting in negative allowances of £12m for our indirect capital activities. Ofgem have agreed to remove this disallowance in their Final Determinations.

Based on the above we propose that the baseline of £11.59m request in baseline should be allowed in full.

NGGTQ22. Do you agree with our proposed GT Project Assessment Process?

The high-level reopener process proposed as part of Draft Determinations is in line with our expectations, having been developed through a series of policy bilateral meetings with Ofgem. However, we seek further clarity around expectations of our submissions to provide information to support these assessments. Having not seen the detailed reopener guidance we are not able to comment on the detail of the process proposed other than at the high level proposed in Draft Determinations. Ofgem need to share a more detailed draft reopener guidance at the earliest convenience to fully understand the impacts of these processes on the NGGT business and our stakeholders.

We seek clarity on what constitutes minimum requirements for the submission, given we have set out elsewhere in our response that this has been unclear for the RIIO-2 Business Plan Incentive and RIIO-1 reopener submissions. This guidance should set out and make clear the level of information required for Ofgem to make their reopener decision. In our view, this would be an investment decision pack comprising EJP and CBA to a similar level of information provided for the August 2020 Hatton submission, ensuring we cover off any of the specific areas Ofgem have set out in their Draft Determinations. We ask Ofgem to provide further clarity on any other specific requirements for inclusion in the proposed guidance.

Ofgem have set out within the Draft Determinations specific areas they wish us to consider for different sites. When considering the right option to be taken forward we will continue to look at the most economically beneficial option for end consumers. We will also need to meet the requirements of our obligations, including those within our environmental permits. Our environmental regulators will need to agree the final option to deliver environmental compliance.

Our view of compressor emissions costs reflecting changes in process since submission is shown below. Please see our responses to NGGTQ23 and 24 for further information on compressor emissions.

Compressor emissions

Table NGGT14 – Compressor emission costs[5]

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	162.01	94.34	156.97
Efficiency	-1.64	-3.37	-7.30
Capitalised Opex adjustment	0.00	-8.19	0.00
Total	**160.36**	**82.79**	**149.67**

NGGTQ23. Do you agree with our proposal to provide baseline funding for Hatton subject to us conducting further volume and cost assessment prior to our Final Determination?

We agree that baseline funding for Hatton should be provided as part of the RIIO-2 price control. However, we do not believe that it should be provided at the level set out within Draft Determination. This figure was an estimate based on a number of assumptions and does not reflect the updated information we have received post the updated tender exercise and more detailed design work. We agree that Ofgem should conduct a further cost assessment ahead of Final Determination as proposed.

The assessment of the need to invest at Hatton, one of the most highly utilised compressor stations on the NTS, has a long history of different requirements, submissions and debate between NGGT and Ofgem, dating back to the May 2015 and the May 2018 reopeners.

The latest in this long timeline was a needs case assessment, submitted by NGGT to Ofgem in June 2019. This was a detailed 79-page document, seeking resolution to the issues unresolved after the May 2018 reopener. Ofgem published a decision on the Hatton needs case five months after submission on the 26th November 2019. This RIIO-1 process had been running in parallel to the RIIO-2 submission.

Further to Ofgem's decision, as part of their continuing volume and cost assessment we submitted two EJPs in March and May 2020. This provided additional information, above the cost proposals and cost benefit analysis shared during the May 2018 reopener, to Ofgem as it became available, reflecting further work undertaken and to reflect elements of the reopener process design and policy that both Ofgem and NGGT had been developing since December 2019. As a result, we have updated our funding request, in line with the increasing cost certainty arising from this additional work to £80m. In addition, since our May 2020 EJP submission we have responded to a number of supplementary questions and produced an updated EJP in August 2020 to support Ofgem in producing this assessment. We have therefore supported further volume and cost assessment prior to Ofgem's Final Determination and will continue to do so.

As part of Ofgem's assessment we do not believe that any tendered costs should form part of any overall efficiency assessment (as a standalone project or as part of the wider RIIO-2 settlement), as due to their nature there is no scope to produce further ongoing efficiency; the efficiency would have already been realised through the relevant tender negotiations.

[5] The table includes costs for the Decommissioning of assets driven by Emissions legislation.

We believe it is essential for us to have the opportunity to comment on Ofgem's assessment based on the updated 2020 tender and design work, given that this has not been included within Draft Determinations. We therefore welcome Ofgem's proposal shared with us bilaterally to consult with us in late September on this revised cost assessment prior to Final Determinations.

Please see our response to NGGT Annex Business Plan Incentive for our response on the BPI penalty relating to Hatton.

NGGTQ24. Do you agree with our proposal to accept the need for investment, provide baseline funding for development work and assess the full project costs during RIIO-GT2 for the compressor projects at Stage 1 - Needs Case Assessment (Wormington, St Fergus, King's Lynn and Peterborough and Huntingdon)?

Funding arrangements to reach final Ofgem reopener decision point

The reopener proposals recognise the need for up front baseline funding for development work to the final Ofgem reopener decision point. However, the Draft Determinations do not propose providing this at a level that covers our projected spend. These allowances should not be based on a fixed percentage of spend for a project but on projected costs. In terms of our projected spend, we have provided additional evidence to support this as part of this response in Annex Major Projects FEED cost proposals.

There are two types of spend in this upfront work; spend relating to pre-construction development costs and spend relating to advanced payments on long-lead equipment items such as the compressor machinery train. We are proposing that these should be treated differently.

To be able to deliver at the pace and certainty required, by the deadlines of the emissions legislation and to access network outages, we require pre-construction development costs to be funded as ex-ante allowances, in line with the costs set out in our annexes. We should be empowered to manage the upside and downside risks and therefore this should be ex-ante funding with no ex-post review of development activities. We believe the proposed unnecessary ex post reviews of pre-construction activities would be intrusive, time consuming, add lengthy delays at a time when agility and flexibility is critical to drive efficient delivery of the project. The reviews will also be resource intensive across network companies, Ofgem and our stakeholders. Pre-construction works are a relatively small cost of these major projects and we do not believe that this ex-post review is proportionate as any benefit to consumers would not offset the resource required to deliver this.

In the funding long lead equipment category, the advanced payment (or down payment) allowance should be trued-up at the final reopener point, as they form an essential part of the build costs for the project. National Grid has limited influence over these costs as compressor unit machinery requirements are tendered with a relatively small number of global Original Equipment Manufacturers (OEMs).

Table NGGT15 below shows the funding split between proposed ex-ante funding for development costs and upfront funding subject to true up.

Table NGGT15 – Funding proposal summary – major projects*

Project	Development costs ex-ante allowance not subject to true-up	Equipment deposit funding request, subject to true-up final reopener decision point	Total funding request
Wormington Compressor	[redacted]	[redacted]	[redacted]
Kings Lynn Compressor	[redacted]	[redacted]	[redacted]
Peterborough Compressor	[redacted]	[redacted]	[redacted]

St Fergus	[redacted]	[redacted]	[redacted]
Bacton Redevelopment	[redacted]	[redacted]	[redacted]
Bacton Refurbishment (Stage 4.2 only)**	[redacted]	[redacted]	[redacted]
Kings Lynn Subsidence	[redacted]	[redacted]	[redacted]
TOTALS	**33.13**	**44.20**	**77.33**

* this table is common across all projects common to the major project reopeners, however the narrative for Bacton and King's Lynn Subsidence can be found in NGGT question 27
** note the refurbishment FEED works are only until the decision point in stage 4.2 of the reopener process. Costs for the 4.3 phase would not change dependent on the redevelopment or refurbishment option.

The data behind these development costs is based on the additional evidence provided in NGGT Annex Major Projects FEED cost proposals. These differ slightly from the proposals from the bilateral meetings as they have been produced from a detailed bottom-up build of costs. These amount to a similar cost for compressors, with an increase in Bacton funding and decrease in St Fergus request. The increase in cost for Bacton redevelopment FEED from the May 2020 bi-lateral engagement is due to a more in-depth resource profile being compiled and by embedding learning from the current Bacton RIIO-1 project. The length to complete FEED has increased to allow for better accuracy before the reopener.

In comparison, as a more detailed profile of St Fergus resource has been completed the total cost has reduced. In addition, some RIIO-1 asset decisions have reduced the scope of the FEED study.

Funding at final reopener point
Given that much of our final reopener submission is based on tendered costs there will be little scope for further efficiencies on final costs submitted. Ofgem's Draft Determinations proposal of a CAI escalator should also mean that our own project management costs are automatically assessed as part the reopener. Ofgem should not apply any overall efficiency assessment to tendered costs, as the efficiency is realised through the relevant tender and subsequent negotiations.

Revised reopener timelines
As discussed with Ofgem bilaterally, we are also proposing revised timelines for these reopeners compared to the Draft Determinations document these are shown as follows:

Table NGGT16 – revised project submission dates – compressors

Project	4.2 submit to Ofgem	4.2 decision date	4.3 submit to Ofgem	4.3 decision date
Wormington compressor	May 2022	October 2022	November 2024	December 2024
King's Lynn compressor	October 2022	Mach 2023	April 2025	May 2025
Peterborough compressor	April 2022	September 2022	October 2025	November 2025
St Fergus site redevelopment[6]	December 2022	May 2023	June 2025	July 2025

We will be working to these timelines which Ofgem propose to set out in the licence as part of the PCD design mechanism. As set out in GT Question 3 it is imperative that Ofgem commit and deliver to making timely decisions on reopener submissions. If this is not the case there is a potential for project delay, adversely impacting the efficiency of the reopener process, our planning and execution of work, utilisation of system access outages, contracting with the supply chain, complying with legislative requirements and delaying benefits to customers from investment.

[6] Regarding St Fergus we understand from paragraph 2.128 of the NGGT annex that Ofgem are considering alternative arrangements for St Fergus compression costs. This has a potential implication for delivery of the timescales above.

However, we believe there needs to be a mechanism whereby if a significant new piece of information were to materialise (for example from Future Energy scenarios or our network capability assessment), or there was a supply chain issue that was preventing a regulatory submission we could agree an adjustment to these timelines with Ofgem. This is important to ensure that when reopeners are submitted they have fully considered the best options for consumers.

St Fergus UM
For the avoidance of doubt, the St Fergus reopener proposal currently covers the following elements of cost:

- Emissions compliance at St Fergus (currently proposed as redevelopment of plant 2) the scope of which is new compression investment and/or asset health investment on retained plant.
- St Fergus subsidence

In addition to the above elements in relation to the St Fergus reopener, we propose that the investment case for interventions on physical security civil assets (e.g. fences) is included for consideration as part of the uncertainty mechanism for this site. This will ensure that overall decision making around major project investments at this site takes proper account of the associated civil security costs looking over the same time horizon. Please see our related response to NGGTQ30 for more information.

The reopener does not include proposed asset health investments which are essential to ensure ongoing safety and reliability of the site. These are covered within our asset health baseline and proposed UM arrangements.

Capitalised opex adjustments
Following engagement with Ofgem through the consultation process Ofgem agreed that capitalised opex adjustments totalling £77m had been incorrectly applied to net capex costs rather than costs inclusive of capitalized labour; effectively resulting in negative allowances of £12m for our indirect capital activities. Ofgem have agreed to remove this disallowance in their Final Determinations.

Also, Ofgem has assumed that all indirect activities flex with capital plan and reduced our baseline CAI opex allowances by 60%, not recognising that we will need indirect costs to support the many reopeners proposed under RIIO-2. Therefore, we are not sufficiently funded support these reopeners. Please see NGGT question 31 for more information.

Recompression
Our response to recompression is included as part of NGGT question 24 (as agreed with Ofgem).

In relation to Ofgem's disallowance of one of our requested recompression units, we have provided further justification for the additional unit alongside this submission in NGGT Annex Recompression EJP, NGGT Annex Recompression CBA, NGGT Annex Recompression backing data costs and NGGT Annex Recompression backing data additional inputs.

We are requesting £[redacted]m funding for both a high and low recompression unit. Investing in two units is justified by our cost benefit analysis and will enable us to reduce our emissions of methane efficiently in the interests of the GB residents.

Our recompression units are used on investment and maintenance work to reduce the amount of methane vented when we need to undertake work that requires depressurization of pipelines. They are transported to the site of the works on HGV's operated and owned by PMC. Our current recompression units are over 20 years old and are obsolete. They also only recompress gas down to 7bar (with the remaining gas being vented to atmosphere) and new technology is now available to recompress gas down to below 1bar avoiding venting of approximately 500-2000 tonnes of methane per annum in RIIO-2. Purchasing new low- and high-pressure units is most cost beneficial as it minimizes the risks associated with getting a new low-pressure unit to work alongside our obsolete old units and will reduce the risk of recompression equipment being unavailable due to failure of old equipment.

As the providence of net zero has grown, it is now paramount that all vented emissions are avoided or mitigated, promoting the need for efficient high- and low-pressure recompression equipment. Net zero, coupled with the works packages within RIIO-2, RIIO-3 and beyond, means there is more need to undertake complete isolation of a pipeline, quickly and safely, to ensure the efficient return of the pipeline to service once the associated work has been completed. The addition of new high- and low-pressure equipment will ensure commitments to Net Zero are met in the most efficient approach currently available.

This investment is key to providing resilience to our current aging legacy recompression units and supports the delivery of a net zero approach to venting of pipelines. The acquisition of both low- and high-pressure units to work in tandem, provides more resilience and efficiency when undertaking a decompressing activity. The investment will ensure a reduction in vented gas when National Grid pipelines need intrusive maintenance. The volume of gas that is vented in these projects is expected to reduce by over 80% resulting in both cost savings of at least £200k/annum for the gas consumer and environmental benefits of working towards Net Zero by removing known methane emissions.

We request Ofgem reconsiders this funding request and provides funding for both the high and low recompression units.

<u>Asset health</u>

NGGTQ25. Do you agree with our assessment approach to asset health work, including our proposal to use a combination of baseline funding, PCDs and a UM for the various cost sub-categories?

Table NGGT17 – Asset health summary (baseline + baseline subject to true-up at reopener only)

Category	Submission (£m)	DD (£m)	Response (£m)
Asset Health Plan (individual intervention level)	616.11	389.68	511.45[7]

[7] *511.45 our sum response, not including direct accepted efficiency, as such it is directly related to 504.73 noted in the following table NGGT18. Refer to file "NGGT Annex_Allowances Reconciliation for further workings of 511.45"*

Other Asset Health (St Fergus Subsidence, Bacton, Kings Lynn, Stopples, GRAID)	38.06	28.04	43.67
Sum Asset Health Plan (Pre adjustments)	654.17	417.71	555.12
Efficiency	-44.33	-21.43	-9.97[8]
Capitalised Opex adjustment	0.00	-49.11	0.00
Total	**609.84**[3]	**347.16**[9]	**545.15**[9]

This represents the proportion of the 4% NGGT efficiency proposal as detailed in NGGT RIIO-2 submission, that NGGT are able to commit to in the reduction of overall capital.

Detailed UM response can be found in our response to NGGTQ37.

The proposed level of asset health spend in our Business Plan was designed to ensure that the level of network risk remained the same at the end of the RIIO-2 period as it is at the start, reflecting our stakeholder feedback. With reducing numbers of compressors on the network, it is important that we properly maintain the remaining compressors, and other assets to ensure we retain the required levels of availability and reliability. This is essential to ensure we have the necessary levels of resilience to accommodate planned and unplanned outages, minimising the impact on our customer's ability to put gas onto and take gas off the network. Ofgem's proposed reductions in Asset Health expenditure in RIIO-2 will increase network risk and restrict capability in RIIO-2 and RIIO-3.

We are deeply concerned with the proposed asset health cost and volume reductions and the design of the associated ex-post adjustment mechanisms being applied to the NGGT business plan. We believe this introduces significant risk to the reliability and resilience of the gas transmission network. In this part of our response, we summarise the principle concerns relating to volume, costs and BPI stage 3 against each theme in the same way as described in Ofgem's National Grid Gas Transmission Annex. This includes correcting for errors that we have identified in the Ofgem methodology used to assess volumes and costs, misinterpretation of historic information provided and additional evidence we have shared with Ofgem since the 9th July 2020.

Our stakeholders have consistently told us reliability is a top priority for them and one that they are willing to pay for. For our business plan they told us they wanted us to maintain the absolute level of risk on the network over the next ten years. The draft determination systematically undermines our ability to maintain the level of risk on the NTS.

The allowances of £390m for asset health detailed in the DD are (10%) lower compared to what we have been spending in RIIO-1 (£435m[10]) and are (37%) lower than our business plan (£616m). This level of funding is not adequate when considering the increasing workload required to address age and deterioration related asset health issues, as a result of which we invested over £62.5m above our allowances to maintain risk on the network in RIIO-1.

Spending in-line with Ofgem's DD allowances will result in the absolute level of risk on the network increasing by 7% over the next ten years, and the long-term risk on the network will worsen by 19%. It is particularly concerning that the asset health allowances in the DD only allows us to deliver 83% of our legislative requirements. We recognise that Ofgem are proposing some uncertainty mechanisms relevant to this area of spend. However, even if all the uncertainty mechanisms proposed are subsequently approved, the long-term risk on the network will still worsen by 14%.

As a diligent asset manager, in the event of needing to prioritise our investments, we will inherently and rightly ensure the safe operation of our network above any other considerations, lack of investment will inherently require prioritisation of safety and environmental risks over availability. The consequence of increased risk on the network is a higher risk of constraints, limiting the ability

[8] *This represents the proportion of the 4% NGGT efficiency proposal as detailed in NGGT RIIO-2 submission.*
[9] *Note rounding implication on the "Total" values above*
[10] Based on an equivalent 5-year period.

of our customers to bring gas on and off the network where and when they want. We know that increased constraints have a direct wholesale market impact for our customers, with these commodity costs being passed through to UK consumers. These costs are significantly above the network costs of maintaining the reliability of the network and is an unnecessary risk to pass on to consumers.

The proposals are in direct contradiction to what our stakeholders told us they wanted, which was to maintain the level of risk on our network over the next ten years. Ofgem has not considered the future consumer consequences of its asset health funding proposals. It has not explained how we are expected to maintain the availability and reliability of our network for consumers, while also spending in-line with its proposed allowances. Overall, Ofgem appears to have ignored the results of our stakeholder engagement, and we urge it to correct for this fundamental failing.

The above is a conservative assessment of the impact the DD allowance will have on risk. This is based only on assets covered by the NARMs methodology. However, the risk impact will be greater if non-lead assets and major projects remain underfunded.

It is vital that Ofgem's Final Determination provides the asset health allowance needed to fulfil our legislative and licence obligations. This can be achieved by adding £115.05m with the associated output commitments to our baseline allowance.

Identification of errors, misinterpretation or lack of understanding
We have noted a number of Asset Health volume reductions that are due to either misinterpretation, error of calculation or requirement for further information to increase understanding.

We have continued to share "Asset Health Evidence Files", documents which serve to offer further data, explanation or challenge to the proposed reductions where relevant and have appended this to our response NGGT Annex Asset Health Volume & Cost Justification – Annex

Themes of our findings include, but are not limited to:

- An error in methodology; the regulator has presumed RIIO-1 deferred remedial work can be utilised as a principle to defer RIIO-2 works. Due to the age, location and utilisation of our network assets, the number of known issues and defects will inevitably increase over time as assets deteriorate and invasive interventions identify issues which cannot be known by non-invasive surveys. Mindful of the RIIO-1 unresolved issues & defects, NARMs methodology and forecasting of "new" issues and defects, we built our RIIO-2 plan over a 10year period and including RIIO-3. A significant level of effort was expended to consider all drivers and variables over both regulatory periods to create a delivery plan that had minimal impact to our customers, maintained a stable level of risk, was operationally deliverable and efficient. Deferring work into RIIO-2 was not an optimal approach, with deferral the only option available as a result of underfunding in RIIO-1, noting the additional RIIO-1 overspend on necessary higher priority works to maintain safety and reliability of the network. Our proposed RIIO-2 plan was established as the most efficient and least interruptive approach to remediating known defects and issues.

- An error in methodology; the regulator has not understood the dynamic nature of Asset Management, specifically, assets will continue to deteriorate beyond our submission build in 2019. We have demonstrated invasive works are required to establish the full scope of remedial actions in several asset types and, as such, our current asset health defects will be a conservative reflection of workload when including further deterioration.

- For our asset health unit costs, there are flaws in the methodology used, which has led to an increased efficiency challenge. This includes flawed cost calculation adjustments, the exclusion of valid high-cost data points from the analysis and misinterpretation of the evidence we provided within our business plan. We have provided evidence to demonstrate why these are unacceptable in our response.

Asset Health main plan

We propose a total baseline allowance at Final Determination of £505m baseline compared to the Ofgem Draft Determination position of £390m.

For each theme, we cover our position on the Ofgem proposed volumes, costs and BPI Stage 3 penalty. The table below summarises our cost and volume response position for Final Determination:

Table NGGT18 – AH proposed allowances for Final Determination

Theme	NGGT Proposed Plan (£m)	Ofgem DD Baseline (£m)	Ofgem DD UM (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD -Volume (£m)	NGGT Response to DD - Cost (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Cabs	31.29	14.38	9.59	23.97	7.32	-	1.86	1.86	1.24	3.11	16.25	10.83	27.08
Civils	79.54	39.97	-	39.97	39.57	0.19	8.39	8.58	13.69	22.27	48.55	13.69	62.24
Compressor	113.69	69.51	-	69.51	44.17	12.78	5.98	18.76	-	18.76	88.27	-	88.27
Electrical	28.48	20.58	-	20.58	7.90	2.35	1.86	4.21	-	4.21	24.79	-	24.79
Pipelines	143.53	112.13	-	112.13	31.41	30.22	18.74	48.96	-	48.96	161.09	-	161.09
Plant & Equipment	156.44	82.28	54.86	137.14	19.30	-	9.83	9.83	6.56	16.39	92.12	61.41	153.53
Valves	63.15	50.83	-	50.83	12.32	5.74	17.10	22.84	-	22.84	73.67	-	73.67
Total	**616.11**	**389.68**	**64.44**	**454.13**	**161.98**	**51.28**	**63.77**	**115.05**	**21.49**	**136.54**	**504.73**	**85.93**	**590.66**

This table is broken down by theme in the following sections.

Table NGGT19 – Project theme – Civils

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Civils	Pipe Supports/ Pits and Ducting	39.29	26.05	13.24	5.61	-	5.61	31.65	-	31.65
Civils	Security and Fencing, Access and Buildings	33.69	9.25	24.43	1.71	13.69	15.40	10.96	13.69	24.65
Civils	Treatment and Drainage, Tanks and Bunds	6.56	4.68	1.89	1.26	-	1.26	5.94	-	5.94
Total		**79.54**	**39.97**	**39.57**	**8.58**	**13.69**	**22.27**	**48.55**	**13.69**	**62.24**

Volume Response

Within the ‘Security and Fencing, Access and Buildings’ sub theme we disagree with Ofgem’s proposal to adjust the plan based on an alternative CBA option. Ofgem’s proposal to select an alternative CBA option will not deliver an actual lower lifetime cost for consumers. Through proposing an alternative CBA option Ofgem suggest NGGT should continue to operate with ~30% of NTS AGIs having fences, gates, roads and paths that are beyond repair and not fit for purpose. We propose to move two items to a volume Uncertainty Mechanism, ‘Site Access Roads and Paths Major Refurb’ (UID A22.18.2.4) and ‘Security - Fences and Gates - AGI (Minor Works)’ (UID A22.18.2.11).

Significant issues relating to these civils assets are known and we must ensure that adequate funding can be made available to ensure an ongoing remediation plan is enacted. The allowances provided in Ofgem's Draft Determination will only cover the already surveyed and planned work in Year 1 of RIIO-2 and leaves NGGT with no funding for the remainder of the period. Failure to facilitate this will lead to increases in security and safety risks at many NTS installations. It is inappropriate to delay this work further and the volume reduction of 90% in both investment areas leaves inadequate funds to achieve basic safety and security standards.

Our National AGI Renovation Campaign (NARC) will visit many AGIs over the course of RIIO-2 to undertake a range of asset refurbishment and replacement work. It is efficient from a delivery standpoint to bundle the civils works into this campaign. Reduced funding now will mean that additional site visits and projects will have to take place in later years raising the overall cost to consumers.

Cost Response
Within the Draft Determination, Ofgem has made errors, such as inconsistent adjustments that has led to unjustified reductions in Unit Costs within the Civils theme. In the 'pipe supports, pits and ducting' sub-theme, Ofgem applied inconsistent adjustments to data provided by NGGT[11] and in another case applied an incorrect adjustment to the number of pit wall transitions remedied[12].

BPI Stage 3
A stage 3 penalty was applied against £28.96m. The change in volumes for Security and Fencing, Access and Building is a result of Ofgem choosing a different asset management approach which we do not support. As such, we do not consider our volumes to be poorly justified and a penalty should not be applied as this is due to Ofgem taking a different method. While we disagree with Ofgem's approach, we ultimately propose Security and Fencing, Access and Building volumes move into an Uncertainty Mechanism.

Errors we have identified in Ofgem's cost assessment of the civils will reduce the costs classified as poorly justified by Ofgem.

Table NGGT20– Project theme – Compressors

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Compressor	Compressor	7.08	6.68	0.39	0.39	-	0.39	7.08	-	7.08
Compressor	Gas Generator Power Train	89.39	59.76	29.63	9.14	-	9.14	68.90	-	68.90
Compressor	Variable Speed Drive	15.79	1.72	14.07	9.15	-	9.15	10.87	-	10.87
Compressor	Vent System	1.42	1.35	0.08	0.08	-	0.08	1.42	-	1.42
Total		**113.69**	**69.51**	**44.17**	**18.76**	**-**	**18.76**	**88.27**	**-**	**88.27**

Volume Response
Within the 'Gas Generator Power Train' sub theme, Ofgem assessed our justification for Gas Generator and Power Turbine Overhauls and have proposed several reductions across several different machines. The overhaul plans were compiled early in 2019 and since this time there have been reductions in forecast running hours for some machines due to a decline from the high flows at St Fergus seen in the years prior to the plan build.

The latest forecast running hours from 2020 has been assessed in line with overhaul requirements and in turn delays some overhaul forecasts. On this basis alone, we can accept all but one (Rolls Royce RB211) of Ofgem's proposed overhaul reductions.

[11] A22.18.1.13 and A22.1.18.1.14
[12] A22.18.1.11

It should be acknowledged that, whilst we are now seeing reductions, future changes in supply patterns could increase running hours again and trigger a need for the overhaul. Given that this work is directly linked to the NARM output, any changes would be justified under the over or under delivery mechanism of the NARMs model.

We have seen a significant reduction in our proposed Compressor Breakdown budget. By its very nature, breakdowns are hard to forecast so the historic spend on compressor breakdowns was utilised as a basis for our RIIO-2 forecast. We proposed a very stretching target to achieve an annual spend lower than the lowest spend observed in the 5 years prior to business plan submission. Ofgem's determination to reduce the annual budget to levels well below that seen in any recent year is unacceptable.

NGGT proposed an approach to split the Compressor Breakdown budget into the volume x unit cost template Ofgem required for RIIO-2 Asset Health work. On reflection, and feedback from Ofgem, we propose to extract the breakdown budget from the "volume x unit" cost template and report as a separate spend line item in the asset health tables similar to how faults are recorded in the OPEX tables. Our NARMS model assumes no benefits gained from spend under this budget so this approach does not affect our overall output target and NARMs reporting.

Cost Response
We disagree with the analysis presented by Ofgem relating to Unit Costs within the Compressors theme for several reasons:

- For the 'gas generator power train' sub-theme:
  - Ofgem misunderstood that the outturn data provided for GE HSPTs was based on service exchanges and not overhauls, and mistakenly proposed a Unit Cost based on an incomparable contract price[13];
  - We have obtained further data from an approved service provider with a long history of maintaining NGGT's assets showing that the price applicable to future Avon overhauls will be substantially higher than the value within the Draft Determination[14];
  - There are several UIDs for which Ofgem has proposed unachievable levels of cost efficiency[15] since NGGT is reliant on a limited number of suppliers, or at times, a specific supplier.
- For the 'variable speed drive' sub-theme:
  - Further information is now available from the OEM that confirms that a refurbishment is a more appropriate solution than a replacement of electrical compressors at Lockerley. NGGT has provided updated cost information to support this revised activity.

BPI Stage 3
There are two sub-themes in compressors that were noted in Ofgem's assessment of low-confidence volume, Variable Speed Drive and Gas Generator Power Train. The volumes received a £7.72m cost reduction. As outlined new modelling data on gas flows indicated a more significant change in future flows than was predicted when the volumes were determined for the December 2019 business plan. We could not have predicted the change in gas flows, these volumes are high confidence against the data available at the time. To assess them as low confidence against different input values is unreasonable.

[13] A22.10.2.12
[14] A22.10.2.4
[15] A22.10.2.5, A22.10.2.11, A22.10.2.13, A22.10.2.14 A22.10.2.15, A22.10.3.6, A22.10.3.7, A22.10.3.11, A22.10.3.12

Additionally, we challenge the significant reduction in the breakdown budget due to poor analysis of data. Our submission was based on a stretch target more efficient than historic outturn costs and therefore these costs are both high confidence and well justified.

Ofgem applied a penalty against £1.77m of lower-confidence costs. This lower confidence assessment is not only unsubstantiated but fundamentally is the result of an incorrect assumption that we would be able to tender some works on our compressors which would result in a cost reduction. We have specific requirements that require specialist expertise, sometimes limited to a single OEM, on many of our compressors which limits the benefits and our ability to achieve competitive tendering.

Table NGGT21 – Project theme - Electrical

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Electrical	Site Electrical Systems	23.24	17.95	5.28	1.60	-	1.60	19.55	-	19.55
Electrical	Standby Power Supplies	5.24	2.63	2.61	2.61	-	2.61	5.24	-	5.24
Total		**28.48**	**20.58**	**7.90**	**4.21**	**-**	**4.21**	**24.79**	**-**	**24.79**

Volume Response

Within the 'Standby Power Supplies' sub theme our plan for asset health intervention on UPS & DC Charger assets aligns to a 15-year lifecycle of replacement. These assets exist to provide standby and backup power supply to essential NTS assets in the event of power failure. Ofgem have proposed we push our intervention lifecycle out to 20 years and have reduced the volumes allowed accordingly. Given our experience of increased defect rates on these assets before the assumed 15 year expected life, extending the intervention period out to 20 years is not pragmatic and increases the risk of not being able to operate NTS assets in an emergency. Given that these assets are for backup purposes we need to intervene before they fail, and it is our recent experience that our 15-year target life is already an optimistic expected life of these assets. Therefore, we disagree with Ofgem's Draft Determination on this basis.

Cost Response

We have no response on the specific Unit Costs within this theme assessed by Ofgem.

BPI Stage 3

In their assessment, Ofgem said they found inconsistencies in volumes that made them consider some volumes to be poorly justified, reducing the volume value by £6.40m. We disagree with the reduction to UPS & DC Chargers as outlined above. The reductions to Site Electrical Systems is as a result of Ofgem proposing to use a different CBA option which NGGT presented as an alternative (not preferred) in the plan. Ofgem proposing to select an alternative CBA option changes the output and so fundamentally different volumes will be delivered. It is wrong to penalise where Ofgem has unilaterally changed the asset management approach.

Table NGGT22 – Project theme – Pipelines

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Pipelines	Depth of Cover	1.08	0.95	0.13	0.13	-	0.13	1.08	-	1.08
Pipelines	Impact Sleeves	4.64	3.81	0.83	6.11	-	6.11	9.92	-	9.92
Pipelines	Pig Traps	4.27	3.50	0.77	0.77	-	0.77	4.27	-	4.27
Pipelines	Pipeline, Coating and CP	131.44	102.02	29.42	41.70	-	41.70	143.72	-	143.72
Pipelines	Watercourse Crossings	2.10	1.84	0.26	0.26	-	0.26	2.10	-	2.10
Total		**143.53**	**112.13**	**31.41**	**48.96**	**-**	**48.96**	**161.09**	**-**	**161.09**

Volume Response
A range of reductions in intervention volumes has been proposed by Ofgem within our pipelines asset health theme and in all cases, we challenge Ofgem's proposals for reasons summarised below.

Ofgem's proposal significantly underfunds NGGT to deliver CIPs inspection and defect remediation requirements. There is a backlog of both surveys and defects and we have provided further detail and justification to support these requirements. Maintaining a significant backlog is not acceptable and is in part due to the reprioritisation of risk required during RIIO-1 due to the asset health programme being underfunded (and NGGTs consequential RIIO-1 allowance overspend). We do not accept Ofgem's position that any new priority defects found in RIIO-2 should be pushed into RIIO-3 for remediation, it creates availability and constraint risks (as feeder outages required to resolve defects are not frequently possible) and does not allow NGGT to manage the backlog down. On this basis, we therefore disagree with Ofgem's proposed reductions in both CIPs survey and associated CIPs defect volumes.

A miscommunication in the business plan SQ process led to Ofgem reducing in ILI defect excavation allowances. This issue has now been clarified with additional justification data provided to support our excavation forecasts as per the December business plan submission.

A revision to the Nitrogen Sleeve defect remediation requirements was proposed through the SQ process as a quantity of known defects requiring remediation were not originally included in the December business plan. This was not accepted as part of the Draft Determination; this information has been reiterated and further clarity provided on a 10-year rolling plan that remediates known defects.

Ofgem disallowed the inspection and defect resolution of two pig traps at the Hatton multijunction on the basis that the connected feeders were to be decommissioned. This decommissioning activity has now been cancelled due to new gas flow requirements. This cancellation has been notified to Ofgem. On this basis, we require these pig traps to be inspected and refurbished as they will be required on an ongoing basis.

Cost Response

NGGT disagrees with several aspects relating to Ofgem's assessment of Unit Costs within the Pipelines theme:

- For the 'pipeline, coating and CP' sub-theme:
  - Ofgem overestimated the number of excavations within the Unit Cost analysis of several UIDs relating to excavations[16] which resulted in an unjustified reduction to the Unit Cost;
  - Ofgem made a series of unjustified adjustments to the analysis relating to the cost of in-line inspections. The use of the median value as proposed by Ofgem is not appropriate since it does not properly reflect the distribution of the costs that NGGT will incur[17];
  - NGGT has provided further detailed information to address Ofgem's concerns about the cost of the work required to upgrade the cathodic protection remote monitoring system[18];
  - For the cost of replacing existing transformer/rectifiers, Ofgem used analysis presented elsewhere within NGGT's Asset Health submission, but omitted elements that are necessary for the successful completion of this work[19];
- For the 'impact sleeves' sub-theme:
  - There is one UID for which Ofgem has proposed an unachievable level of cost efficiency since NGGT is reliant on a limited number of potential suppliers[20].

BPI Stage 3

In their assessment, Ofgem identify low confidence issues with CIPs digs, reducing CIPs digs by over 25%, and digs for capital refurbishment by nearly 60% in the RIIO-2 period. The overall volume reduction in pipelines equates to a £23.5m reduction. As noted, this reduction in work is not sustainable in the long term and puts the entire NTS at significant risk. The volumes are well justified and should be re-instated.

A penalty was applied against £3.64m in lower-confidence costs, particularly regarding remote monitoring (A22.16.4.11). We have provided further detail relating to the scope and costs of such work in an additional appendix. Costs are high confidence as they're based on specific OEM data for the assets, with National Grid costs to access and install based on historic outturn data.

Table NGGT23 - Project theme - Valves

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Valves	Valves	63.15	50.83	12.32	22.84	-	22.84	73.67	-	73.67
Total		**63.15**	**50.83**	**12.32**	**22.84**	**-**	**22.84**	**73.67**	**-**	**73.67**

Volume Response

For the Valves asset health theme, there is only one area where significant reductions have been proposed by Ofgem; major refurbishment of vent and sealant lines. Our plan aims to achieve the lowest cost intervention by refurbishing assets where possible and only replacing assets where they are beyond repair.

Ofgem had incorrectly assumed there was a double count in the plan whereby NGGT would attempt to refurbish all vent and sealant lines with defects then assume that the refurbishment would not resolve the issue requiring a further replacement intervention. We have since clarified for Ofgem the different drivers for refurbishment and replacement of vent and sealant lines with the appropriate

[16] A22.16.4.1, A22.16.4.4, A22.16.4.7 and A22.16.4.9
[17] A22.16.4.5
[18] A22.16.4.11
[19] A22.16.4.12
[20] A22.16.2.2

underlying detail and data. Therefore, we disagree with Ofgem's proposed reduction of all vent and sealant line refurbishment volumes.

In reassessing our business plan following the Draft Determination an issue has been identified relating to actuator replacement at our St Fergus terminal. Our plan intended to phase actuator replacement over a 10-year period. Since our plan was submitted a revision to our plan is now required and all actuator replacements must be front loaded in the RIIO-2 plan. The driver for actuator replacement is the "gas actuating ring main" which powers all on site actuation. This ring main requires decommissioning as soon as practicable and as such all required actuators must be replaced with the electro-hydraulic type before the decommissioning can take place.

Cost Response

There are a handful of areas where NGGT disagrees with the analysis that Ofgem presented relating to Unit Costs within the Valves theme:

- Ofgem disregarded the two highest cost projects for which NGGT provided outturn cost data[21]. Both data points are valid projects that, with minor adjustments for scopes covered within other UIDs, demonstrate the potential cost of this work activity which should be included in any outturn data. The nature of valve replacements is that there will always be variation in costs depending on the valve location on the network and local conditions and considerations. It is therefore necessary to consider more complicated replacements as well as simple jobs to ensure the overall sample is representative of what is experienced, this is the nature and explicit purpose when producing unit cost from outturn data.
- Where Ofgem removes costs relating to scopes from other UIDs, it should apply the final Unit Cost applied to such activities to avoid inconsistency[22];

BPI Stage 3

A penalty was applied against valves volumes with a value of £1.49m. This was due to an incorrect assumption of double counting by Ofgem of vent and sealant line volumes. We have resubmitted clear evidence to show this is not the case.

A stage 3 penalty was applied against £10.45m of lower confidence costs. Ofgem's challenge on this was the lack of available outturn data, at the level of granularity required. Ofgem used the data in their analysis and further reduced the volume of data with the unjustified removal of high cost projects. The inclusion of these projects is well justified, as are these costs.

Table NGGT24 – Project Theme - Plant & Equipment

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Plant & Equipment	Above Ground Pipework, Cladding and CP Systems	130.78	114.42	16.36	8.07	5.38	13.45	76.72	51.15	127.87
Plant & Equipment	Filters, Scrubbers and Preheaters	17.16	15.19	1.97	1.18	0.79	1.97	10.29	6.86	17.16
Plant & Equipment	Pressure Reduction, Flow Control and Slamshut Systems	8.51	7.53	0.98	0.59	0.39	0.98	5.10	3.40	8.51
Total		**156.44**	**137.14**	**19.30**	**9.83**	**6.56**	**16.39**	**92.12**	**61.41**	**153.53**

21 A22.14.1.5, A22.22.6.5, A22.14.1.14, A22.14.1.22, A22.22.6.9, A22.22.6.1
22 A22.14.1.8, A22.14.1.17, A22.14.1.25, A22.22.6.7, A22.22.6.2, A22.22.6.11

Volume adjustments have been made as part of the Draft Determination relating to the quantity of sites covered by the painting programme. This adjustment was made during the submission SQ process, with which NGGT proposed and agreed.

The entire theme has been placed into an Uncertainty Mechanism. Clearly Ofgem accept the need to do the volumes of work as we have seen no additional volume reductions.

We cover our approach to managing the reopener uncertainty mechanism in our response to question NGGTQ37.

Table NGGT25 – Project Theme - Compressor Cabs

Theme	Sub-theme	NGGT Proposed Plan (£m)	Ofgem DD Total Plan (£m)	Delta NGGT Proposed Plan vs Ofgem DD (£m)	NGGT Response to DD - Baseline (£m)	NGGT Response to DD - UM (£m)	NGGT Response to DD - Total (£m)	NGGT Restated Plan for FD - Baseline (£m)	NGGT Restated Plan for FD - UM (£m)	NGGT Restated Plan for FD - Total (£m)
Cabs	Cab Infrastructure	24.33	18.80	5.53	1.46	0.97	2.44	12.74	8.49	21.23
Cabs	Fire Suppression Systems	6.96	5.17	1.79	0.40	0.27	0.67	3.51	2.34	5.84
Total		**31.29**	**23.97**	**7.32**	**1.86**	**1.24**	**3.11**	**16.25**	**10.83**	**27.08**

Various volume reductions have been proposed by Ofgem in this theme due to concerns regarding investing to reduce cab risks at compressors where life is limited (e.g. RIIIO-3 decommissioning planned) or running hour forecasts are low. However, given the entire theme has been placed into UM, we propose that survey work combined with updated running forecasts and our overarching fleet strategy will form the basis of the reopener information to provide assurances that investments going forwards are justified and agreed with certainty.

We cover our approach to managing the reopener uncertainty mechanism in our response to question NGGTQ37.

NGGTQ26. Do you agree with our proposed approach for costs confidence, including our view and rationale for high and low confidence cost categories and costs subject to a BPI Stage 3 penalty?

Specific Asset Health cost confidence and BPI stage 3 penalty at theme level is captured within question NGGTQ25.

We continue to work constructively with Ofgem to provide additional information, over the minimum requirements, to help Ofgem assess our costs; providing a level of granularity not previously seen or requested in previous price controls.

To support Ofgem's updated expectations, we prioirtised achieving outturn data, as agreed with the Ofgem, for the top 30 unit costs for Asset Health, approximately 60% of the £616m of investment sought. The outturn costs identified prodominately recent work completions, inherently including efficiency and/or innovation savings achieved within the RIIO-1 period. In addition to this we offered a further 4% Capex efficiency reductions on our plan.

We rigourously reviewed thousands of data points to remove anomolies, ouliers where relvant and ensure known efficiency was included to achieve realistic and challenging cost values.

Mindful the sheer scale of this activity, and previous agreement with Ofgem regarding prioritisation of unit costs, we're disappointed by Ofgem's penalisation of unit costs in general, and on the remaining 40% of agreed lower prioritiy works, resulting in proposed reductions of £29.5m.

Ofgem has applied a reduction to all costs, unless we provide specific cost justification for the deprioritised 40%. This is despite Ofgem providing no external benchmarking data to suggest our costs are inefficient and is in addition to further efficiency challenges that Ofgem applied to the business plan. The reduction across all unit costs unless specifically evidenced by us or valid external benchmarks is unjustified and has a disproportionate impact on the Asset Health plan.

We maintain that Ofgem should apply no adjustments to the unit costs submitted, unless there is specific information that the unit cost is inaccurate or is not efficient.

The current approach is not consistent with the Principles of Better Regulation[23]. Reflected in the Gas Act, these require Ofgem to have regard to *"the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed"*.[24]

Proportionality *(Regulators should only intervene when necessary. Remedies should be appropriate to the risk posed, and costs identified and minimised)*
When submitting evidence relating to unit costs, we focussed, as agreed, on those interventions that had the highest overall cost within the business plan rather than submitting detailed justification papers relating to more than 300 interventions that together build up the Asset Health business plan[25]. Ofgem agreed that this approach was proportionate[26]. It is therefore unjustified to propose a unilateral reduction to all other interventions on the grounds that "*the same efficiencies [are] to be delivered within these other costs*"[27].

Accountability *(Regulators must be able to justify decisions, and be subject to public scrutiny)*
As outlined in our business plan submission[28], we put significant effort into creating relevant external benchmarking data to provide us with confidence that our costs are efficient. This demonstrated the complexity of getting consistent cost build-up across different external industries and the uniqueness of GT with our process safety responsibilities. For example, a large excavation containing a high-pressure gas pipe at a significant distance from the nearest road is very different from other utility excavations which have their own challenges such as traffic management. Within our business plan, we have provided data at an unprecedented level of granularity, and this posed difficulties both with capturing data from our own experience and when seeking to compare to external benchmarks. Ofgem has provided no evidence to show that the unit costs provided are inefficient when compared with external benchmarks. In fact, we have participated in an international TSO benchmarking study commissioned by the Council of European Energy Regulators (CEER) of which Ofgem is a member. The study commenced in February 2018 and the final report was recently published by CEER. Participants, which comprised of 29 gas TSOs from 16 European countries. Consistent with the previous gas TSO benchmark of this type, we feature as an efficient peer across the range of models.

Consistency *(Regulation should be predictable in order to give stability and certainty to those being regulated)*
This treatment of lower materiality investments is inconsistent both with the approach taken in RIIO-1 as well as to other areas of the RIIO-2 Draft Determinations. For example, for transmission companies all IT investments less £1m have been fully funded with no prejudice to the robust assessment of higher value investments.

[23] Better Regulation Task Force, 'Principles of Good Regulation'.
[24] Gas Act 1986, s.4AA(5A)
[25] As outlined in NGGT_A20.17
[26] Ofgem, NGGT Annex, para 3.176
[27] Ofgem, NGGT Annex, para 3.176
[28] See NGGT_A20.17

Targeting *(Regulation should be focused on the problem, and minimise side effects)*
Within our Asset Health plans, we offered a 4% efficiency improvement through future innovations which Ofgem has removed and replaced with their own approach. This is additional to individual asset health unit cost deductions and general approach for deprioritised work. This creates unachievable levels of efficiency overall. The general reduction applied to unit costs for which specific cost calculations were not provided removes £29.5m from the Asset Health budget[29] prior to the application of further efficiency challenges.

BPI
We summarise our position on the Stage 3 BPI penalties as follows, with more granular reasoning noted in our response to NGGTQ25 and associated appendices. Lower confidence, poorly justified cost as assessed by Ofgem in the asset health plan have been subject to Stage 3 of the BPI. This amounted to a total penalty of £10.07m, £3.26m against costs and £6.81m against volumes. In our challenge to Ofgem's review of costs and volumes we reject the application of the Stage 3 BPI to a significant proportion of these disallowed costs and volumes.

While we have not received at a UID level where penalties were applied, Ofgem did indicate in their assessment where they found low confidence in cost and volumes and where the Stage 3 penalty was assessed at a theme level with some narrative. Assumptions were made linked to our cost confidence and Ofgem feedback to understand which UID the penalty was applied to.

BPI and Asset Health Cost Reductions
Overall, the cost element of the Asset Health GT plan was subject to a BPI penalty of £3.26m. Of that there are four themes where we challenge the assessment, addressing up to £2.6m of this penalty. These themes are;

- Pipelines (subtheme, Pipeline, Coating & CP)
- Compressors (subtheme, Gas Generator Power Train)
- Valves
- Civils (subtheme, Pipe Supports, Pits and Ducting)

The amounts of Stage 3 BPI penalty we are challenging are shown in the table below.

Table NGGT26 – Stage 3 BPI penalty challenge areas

Area of challenge	BPI on Costs (£m)
Pipelines, Pipeline, Coating and CP	0.68
Compressors, Gas Generator Power Train	0.16
Valves	1.04
Civils, Pipe Supports, Pits & Ducting	0.70
TOTAL	**2.6**

BPI and AH Volume Reductions
There are five themes in Asset Health to which a penalty was applied to the volume element and where we challenge Ofgem's DD proposals;

- Pipelines (subtheme Pipeline, Coating & CP)
- Compressors (subthemes, Variable Speed Drive and Gas Generator Power Train)
- Valves
- Civils (subtheme Security and Fencing, Access and Buildings)
- Electrical (subthemes, Site Electrical Systems and Standby Power Supplies)

The total volume penalty assessed by Ofgem is £6.81m and our analysis challenges over £6m of it, with detailed reasoning in NGGT25 question response and associated appendices.

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[29] Assuming NGGT volumes and the reduction in unit costs as proposed by Ofgem. Including Civils, Compressors, Electrical, Pipelines and Valves themes. Cabs and Plant and Equipment have been excluded from this calculation since both will be subject to UMs.

Table NGGT27 – BPI volumes

Area of challenge	BPI on Volumes (£m)
Pipelines, Pipeline, Coating and CP	2.32
Compressors, Variable Speed Drive	0.29
Compressors, Gas Generator Power Train	0.48
Valves	0.15
Civils, Security and Fencing, Access and Buildings	2.19
Electrical, Site Electrical Systems	0.39
Electrical, Standby Power Supplies	0.25
TOTAL	**6.07**

In addition to asset health we have also challenged cost confidence and BPI Stage 3 assessments in various other questions as relate to other cost areas in NGGTQ27- NGGTQ30.

More broadly Ofgem is placing most weight on a subset of one of the four ways to prove costs are high confidence, SSMD paragraph 11.37: econometric industry benchmark evidence. This method is not available to the transmission companies as there are an insufficient number of companies and because of their disparity in size and networks. The assessment against the other three ways to demonstrate high confidence is not consist with the Principles of Better Regulation[30] reflected in the Gas Act that require Ofgem to have regard to *"the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed"*[31] because of the wide discretion Ofgem has given itself in its limited guidance. Ofgem's approach makes it materially harder for a transmission company to show it has high-confidence costs.

As related to BPI Stage 3 penalties Ofgem has a skewed approach to assessing whether companies' costs proposals which it deems "lower confidence" are sufficiently justified. In making this assessment, Ofgem reviews a range of cost data which is often not available to companies, and systematically targets the lowest cost, imposing a Stage 3 fine where the company's submission was above that cost. This is not a reasonable approach for assessing the quality of a business plan: Ofgem should be considering whether a company's proposal was justified on the basis of the information available to it.

When assessing whether "lower confidence" costs were "poorly justified", Ofgem has then penalised companies if their proposed costs exceeded those associated with Ofgem's preferred option, without making any adjustment for the higher level of service / output which companies were proposing. This is not a logical basis for comparison as it is clearly wrong to base an efficiency assessment on costs alone without also taking into consideration the level of output.

Please see NGGT Annex Business Plan Incentive for our full response on BPI.

<u>Other asset health costs</u>

NGGTQ27. Do you agree with our proposed approach to approve the need for investment, provide development funding and assess the full project costs through a UM during RIIO-GT2, for the Bacton, St Fergus subsidence and King's Lynn subsidence projects?

The broad regulatory process proposed for the projects under this question are similar to that proposed for compressors. To avoid repetition, please see question 24 for our response on the regulatory arrangements, including in relation to funding arrangements to reach final reopener decision point and summary cost proposals. Below is commentary on the specific projects that fall under Q27.

[30] Better Regulation Task Force, 'Principles of Good Regulation'.
[31] Gas Act 1986, s.4AA(5A)

St Fergus subsidence

Please note that this response does not include St Fergus subsidence as this is included as part of the St Fergus redevelopment as responded to in question 24. Please note that the specific subsidence work is likely to need to be done in advance of the reopener which exposes us to regulatory funding risk and ex-post regulation.

Bacton FEED costs

Within the Draft Determination, it was stated that Ofgem do not necessarily agree with the option to redevelop the terminal and would like us to pursue the asset health replacement option in tandem. The additional work required to progress the asset health option to a similar accuracy and confidence to the redevelopment has been calculated to be [redacted] up to the reopener, at which point a preferred option would be selected. This additional cost is due to the complexity of trying to model and predict asset condition of an aged, complex site over a 25 year time period to the accuracy required. It is in addition to the [redacted] required to progress the redevelopment option to stage 4.3 of the investment process.

This work includes a third-party study to accurately assess the current condition and remaining life of the site assets, allowing us to compile a more accurate and efficient programme and costs based on the current and predicted site risks until 2050. This can then be compared directly with the whole life costs for the redevelopment, which will be progressed alongside.

The increase in cost for Bacton redevelopment FEED from the May 2020 bi-lateral engagement is due to a more in-depth resource profile being compiled as the project has advanced into stage 4.2 of the investment process, and by embedding learning from the current Bacton RIIO-1 project. The length to complete FEED has increased to allow for better accuracy before the reopener. Note that as a result of this work other FEED costs have reduced (relating to St Fergus project covered in NGGTQ24).

King's Lynn Subsidence

In our response to NGGTQ24 we explain that we believe development costs major projects should be provided on an ex-ante basis. We note that in the Draft Determination Ofgem state a policy that proposes 5% of forecast outturn costs for non-compressor projects. Whilst Ofgem have applied this policy to some projects we note that Ofgem has chosen to not equally apply this policy to the funding for King's Lynn.

Revised reopener timelines for Bacton and King's Lynn subsidence

As discussed with Ofgem bilaterally, we are also proposing revised timelines for these reopeners compared to the Draft Determinations document these are shown as follows:

Table NGGT28 - revised project submission dates – Bacton and King's Lynn subsidence

	4.2		4.3	
	4.2 submit to Ofgem	4.2 decision date	4.3 submit to Ofgem	4.3 decision date
Bacton	February 2022	July 2022	November 2022	January 2023
King's Lynn subsidence	April 2022	September 2022	N/A	N/A

We have set out further points in relation to this as part of our response to NGGT question 24.

Bacton UM

In relation to physical security major asset health upgrades at Bacton, we propose that the need case for capex interventions on PSUP civil assets (including gatehouse and fences) is included for consideration as part of the Bacton terminal site redevelopment reopener for this site. This would ensure that overall decision making around major project investments at this site takes proper account of the associated civil security costs looking over the same time horizon. Please see our related response to NGGTQ30 for more information.

Capitalised opex adjustments
We have concerns around capitalised opex adjustments and our ability to respond to reopeners. Please see our response to NGGT question 24.

NGGTQ28. Do you agree with our proposed baseline allowances for Stopples, GRAID and decommissioning of redundant assets and compressors?

Stopples
We have no challenges with the proposed stopples response in Draft Determination, noting no volume or cost reductions are suggested.

GRAID
We do not agree with the proposed funding allowance reduction for GRAID from £18.3m to £10.0m.

Project GRAID provides a novel robotic technique for inspecting non-piggable sections of pipeline, primarily associated with AGIs, which previously required excavation and depressurisation to inspect. Investment is required to use this technique on AGIs and costs will vary depending on complexity of pipework unique to sites. We maintain the requirement for 20 inspections through RIIO-2 to align with our outages which will substantiate through completion data, further works.

We understand that the uncertainty in the remediation requirements is being handled through the Plant and Equipment Uncertainty Mechanism (UM) and therefore propose that the £1.0m stated for remediation costs will be covered under this mechanism, with any efficiencies considered in that submission. Future efficiencies from GRAID will come from a reduced level of remediation work. It is therefore appropriate that the efficiencies from GRAID in terms of avoided remedial excavations is assessed as part of the reopener process and the benefits not used to offset our GRAID business plan submission.

As demonstrated in our Plant and Equipment asset health response in Q25 and our need to utilise an UM it is very difficult to quantify the cost of asset maintenance activity required based on the current cathodic protection (CP) data in place. The GRAID robotics system will provide insight into the actual status of our assets in locations where we cannot currently operate our pipeline inspection gauges (PIGs). The numbers provided for RIIO-2 are based on 20 compressor stations being inspected throughout RIIO-2, all of which have an existing scheduled outage for other remedial work. The outages are a requirement for the use of the system, however efficiencies can be made by bundling the use of GRAID with other schemes. These inspections will provide us valuable information in regards the assets which will enable improved efficiency in later remedial work and provide an insight into the accuracy of the CP defect data for identifying potential AGI pipework coating and corrosion defects. It should be noted that inspection using GRAID has the potential to increase the volume of pipework defects beyond the known volume of CP defects as well as confirming that CP defects have not led to corrosion. I.e. the volume of excavations could go up or down following a GRAID inspection, but to surmise, our asset knowledge would lead to increased targeted intervention, inherently more efficient, and preventative actions to ensure reliability and availability.

We agree that the large-scale project (Bacton) benefitted from the efficiencies being made using an existing contractor already on site to reduce the cost. As stated, we have planned for the GRAID platform to be utilised during existing outages, so it may be possible that similar efficiencies could be achieved in the future. Whilst this is not a confirmed position at present, as those contractors have not been appointed, we would endeavour to work with the appointed parties to gain the same efficiencies. We therefore agree to the reductions in the large-scale costings of £0.9m across RIIO-2.

A key driver for the use of the GRAID platform is to provide the certainty around the integrity of the pipelines which have previously not been inspected. Without this data, it is not possible to reliably define the number of excavations that can be avoided in a given time frame as the platform has not been deployed at the areas of interest. Whilst data was collected from both trial locations during the NIC project the primary driver for the location on site was to test the platform in a live environment. It should be noted that at Bacton a previously buried asset was located by GRAID during the NIC trial and its location marked above ground, that on its own gave certainty for the location that should be excavated and provides an indication of the benefit that GRAID could bring. Until the platform is deployed during RIIO 2 across the 20 sites proposed it is not known how many excavations it will save but what it will provide is the certainty that if we chose to excavate it is in a location that requires attention and that unnecessary excavations are reduced.

Regarding the proposal to offset against benefits, we hope to utilise this system to inform our repairs currently scheduled and improving their efficiency via knowledge of the location and state of the asset. Following the conclusion of the GRAID NIC project a key recommendation was that the GRAID sensor array could be significantly improved to increase the quality and quantity of data collected. This has led to the creation of a follow-on NIA project to merge the acoustic resonance technology (ART) with the GRAID platform. This work is currently underway and will deliver a functional robot at the end of RIIO-1, therefore, the anticipated use of the GRAID inspection system in RIIO-1 has not been possible and has not informed our RIIO-2 asset health activity. The original benefit case of 7-8 excavations a year saved was developed during the 2014 NIC project and as the reality of GRAID is understood more with the application of the tool it is apparent that there will not be a linear saving. With GRAID providing certainty where excavation is needed, the benefit of the tool will be in providing robust information for the UM for the remediation work required.

We are therefore seeking a total of **£16.4m** for GRAID in RIIO-2.

Table NGGT29 - GRAID

Movement	Value (£m)
Draft Determination	£18.3
Remediation costs, now included as part of proposed UM	-£1.0*
Large scale project example efficiency	-£0.9*
Final Determination Value Sought	**£16.4**

* please note that these reductions have been removed from the 4% efficiency overlay

Decommissioning of redundant assets and compressors

Table NGGT30 - Decommissioning costs[32]

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	82.57	72.67	82.57
Efficiency	-3.86	-4.37	-9.78
Capitalised Opex adjustment	0.00	-9.91	0.00
Total	78.71	58.38	72.79

We welcome Ofgem's provision of a baseline allowance for redundant assets. We believe that addressing our redundant asset base during RIIO-2 is the right outcome for consumers and this is supported strongly by stakeholders.

In terms of non-compressor decommissioning we do not agree with the removal of 8.1% of the total project costs for risk. Firstly, we do not believe it is appropriate to apply this reduction principle these to the "customer funded disconnections".

These customer funded disconnection costs are based on outturn projects actuals, based on the weighted average costs from of a number of site disconnection projects, as explained in

[32] The table shows costs for the Decommissioning of assets not driven by Emissions legislation.

NGGT_SQ_ENG_30. No additional risk was added for our submission. Ofgem should reinstate this 8.1% removal for the customer funded disconnection projects.

For other non-compressor redundant asset projects, Ofgem themselves recognise that in this area there appears to be a lack of comparable decommissioning projects completed during RIIO-1. Whilst Ofgem's policy sets out a cap on risk, we believe that these additional costs are justified to manage a higher level of unknown risk across this workload. However, we are not able to provide any further information that has not been provided already at this stage.

Decommissioning at [redacted] and additional customer disconnections
As stated in our December business plan our redundant assets are largely driven by the requirements of our customers.

[redacted]

[redacted]

[redacted]

[redacted]

We welcome the opportunity to discuss with Ofgem the risk tradable PCD outlined in our business plan. This would enable us, throughout RIIO-2 to re-prioritise redundant asset decommissioning projects as customer requirements change.

BPI penalty

NGGT did provide appropriate supporting information on efficiency estimates. Rather than use the potential, but unproven, multi-unit discount postulated by the Amec Foster Wheeler report, our business plan applied a 4% overlay efficiency on a number of areas of our plan, which satisfies the Minimum Requirement. If Ofgem takes the view that this was not an appropriate challenge, that is a Stage 3, rather than a Stage 1 assessment under the BPI.

NGGT did provide appropriate supporting information on forecast costs. There are no historic compressor decommissioning costs, as the nature of these particular works is that they are not repetitive or frequent. In discussion with Ofgem, the regulator has acknowledged that there is no benchmarking data available and that we are therefore unable to show our efficiency against such benchmarks. We made a decision to use the costs from a Subject Matter Expert (Amec Foster Wheeler) report, rather than repeat a costing exercise which, without any real site activity to provide extra information would be an unnecessary, unjustified cost. These studies by their nature, are highly bespoke. The information submitted on forecast costs therefore satisfies the Minimum Requirements. For more information please see NGGT Annex Business Plan Incentive.

Non-operational capex

NGGTQ29. Do you agree with our proposed assessment approach and baseline allowances for non-operational Capex costs, including IT&T, STEPM, property and vehicle fleet investment?

Table NGGT32 – Non-operational Capex

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	135.07	47.50	127.62
Efficiency	0.00	-2.38	0.00
Capitalised Opex adjustment	0.00	-5.50	0.00
Total	**135.07**	**39.62**	**127.62**

Table NGGT33- GSO Capex

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	161.43	26.97	118.33
Efficiency	0.00	-1.47	0.00
Capitalised Opex adjustment	0.00	-0.57	0.00
Total	**161.43**	**24.93**	**118.33**

Table NGGT34- GTO IT capex

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	90.20	7.91	84.02
Efficiency	0.00	-0.40	0.00
Capitalised Opex adjustment	0.00	-0.96	0.00
Total	**90.20**	**6.55**	**84.02**

Table NGGT35 - GSO IT capex

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	158.81	26.97	115.71
Efficiency	0.00	-1.47	0.00
Capitalised Opex adjustment	0.00	-0.57	0.00
Total	**158.81**	**24.93**	**115.71**

Table NGGT36 - GT IT capex

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	249.01	34.88	199.73
Efficiency	0.00	-1.86	0.00
Capitalised Opex adjustment	0.00	-1.53	0.00
Total	**249.01**	**31.48**	**199.73**

IT & telecoms

Ofgem has proposed a reduction in our baseline funding for IT & telecoms of £216.7m from a submission of £251.6m. With £208.2m being proposed for uncertainty mechanism. This provides baseline funding for only 6 of 66 project lines. We do not agree with the assessment approach and the baseline allowances it has resulted in.

The assessment undertaken identifies the needs case for all our assessed projects is acceptable and not the blocker to ex-ante funding. It also identifies that of assessed projects cost certainty is a contributing factor to inclusion in UM for only three.

The main blocker to ex-ante funding is an assessment of project maturity that sets an unreasonable expectation of the maturity of investments, straying into areas of delivery risk that networks have always been expected to manage by shifting them instead to consumers.

We understand the assessment approach for IT costs was designed after the business plan submission in December 2019. Consistent with this there was no IT specific business plan guidance provided that identified additional areas of assessment beyond the general expectation set by the SSMD.

The assessment employed goes beyond the expectation of the business plan assessment process as outlined in the RIIO-2 tools for cost assessment consultation published in summer 2019. For IT & telecoms investments the relevant primary workstream as stated in paragraph 5.6 of the RIIO-2 tools for cost assessment are (i) needs case assessment and (iii) cost assessment.

The Draft Determinations featured inconsistent treatment between National Grid Gas Transmission and Electricity Transmission for the same shared projects. For example, all NGET indirect projects have been included in the totex baseline whilst the same projects in NGGT have been placed in the uncertainty mechanism. Low materiality projects that were fully funded for almost all other networks have also been included in the uncertainty mechanism in our Draft Determinations. Since publication of the Draft Determinations we have highlighted and discussed these items with Ofgem, provided mapping documents to clearly identify how shared investments feature across the various BPDTs and are confident these errors will be addressed for Final Determinations.

We can see the benefit of having a re-opener for very uncertain projects. However, we are concerned that the current broad scope will create a high burden on both Ofgem and networks inconsistent with the risk to be managed. Currently included in the uncertainty mechanism are many necessary, straightforward, like-for-like type investments to maintain systems and capability. To retain such a broad re-opener would not protect consumer interests.

If Ofgem does not move materially from its current position of minimal baseline and significant UM funding then given the potentially large numbers of projects to be developed ahead of the re-opener, we believe there is a strong case for ex-ante allowances to support this development of capital projects.

Of the projects currently funded in baseline we have seen an efficiency reduction (circa 20% of allowed baseline) based on the rolling forward of the too broad assessment approach. There is no evidence (whether historic or based on industry best practice) to support the arbitrary levels of cost adjustments, up to a maximum reduction of 25%, applied based on the outcome of a qualitative assessment approach.

We asked one of our third-party providers, who support us in delivering IT projects, to help us identify best practice and research related to how the cost of IT investments change over time. Several sources observe the risk of IT investment cost over-run and provide no substantiation that a 25% reduction is a reasonable outcome against a supported point estimate.

Surveys of industry professionals around the uncertainty of software project costs indicate that there is 25% chance of a project being below a point estimate; and a 30% chance it will be twice the point estimate[33] This same research suggests that an outcome 25% below the point estimate would have a confidence level of between less than 5% and around 10% and shows the expected “long tail” of IT investment costs.

An article in the Harvard Business Review in September 2011[34] discusses a global study of 1,471 IT change projects. “The average overrun was 27%—but that figure masks a far more alarming one. Graphing the projects’ budget overruns reveals a “fat tail”—a large number of gigantic overages.”

A paper presented at the Project Management Institute Global Congress 2007[35] discusses the cone of uncertainty, with expected outcomes always skewed towards overrun against the point estimate and a likely range at budgeted stage of +30% to -15%.

A paper published in the Journal of Emerging Trends in Computing and Information Sciences[36] reviewed research publications on estimating accuracy of IT project costs. Amongst its many observations are the following.

- “Estimates are mostly overoptimistic, and underestimating is a problem for the software industry. 60-80% of the projects experience effort or schedule average overruns of 30-40%.”
- “…cost estimates at the conceptual stage are in the range of -30% to +50%, which reduces to between -5% and +15% when the detailed design phase is entered.”

These available and cited pieces of research show that any bias likely to be within estimates of IT investments is optimism. Providing allowances close to the point estimates submitted by networks will still result in strong incentives to ensure that world class project management and controls are applied to IT investments to avoid the far more likely outcome of cost overrun.

Furthermore, to provide baseline allowances as low as 75% of the submission cost risks leaving us unable to deliver the requirements of the investment. Projects may need to be descoped resulting in more and potentially costly investment in the later part of the RIIO-2 period or RIIO-3 and beyond.

We are confident Ofgem can address errors of judgment leading to inconsistencies across multiple aspects of the IT & telecoms assessment approach. Correcting these will ensure a strong foundation to agree reasonable allowances for our IT investments that will provide the certainty over the reliability and resilience of the systems we rely on, that our stakeholders need and allow us to play our part in the digitalisation of the energy industry, the green recovery and GB’s net zero ambition.

In reaching Final Determinations Ofgem needs to adapt its cost assessment methodology to:

- be consistent with the expectation of a cost assessment set through the RIIO-2 tools for cost assessment consultation, focusing on need case and cost assessment;
- provide baseline allowance for projects with satisfactory need case and cost assessments, reducing the volume of projects subject to re-opener;

[33] https://www.simula.no/sites/default/files/publications/files/iwesep-nara-2018_jorgensen.pdf
[34] https://hbr.org/2011/09/why-your-it-project-may-be-riskier-than-you-think
[35] https://www.pmi.org/learning/library/successful-outcome-forecasting-projects-7231
[36] http://www.cisjournal.org/journalofcomputing/archive/vol6no6/vol6no6_4.pdf

- address inconsistencies of assessment between networks;
- reduce the punitive maximum reduction of 25% to be commensurate with relevant IT experience and best practice.

Notwithstanding our concerns around the assessment approach we believe that in several areas we have currently been assessed less favourably purely because we did not give visibility of relatively simple project management artefacts.

To remedy any issue of visibility we have been working collaboratively with Ofgem and Atkins since the Draft Determinations to agree the right additional evidence to ensure that we properly represent the genuine maturity of many more of our investments. As discussed with Ofgem, we expect that this will allow more of our IT investments to be funded in baseline even under the current assessment approach. This will reflect their current maturity whilst also ensuring efficient delivery of planned programmes of work through the period.

We propose to move £159m back to baseline, £69m as a result of inconsistencies in assessment between ourselves and NGET, and £90m based on further evidence provided.

We engaged with Ofgem in the period after submission through both the SQ process and several bilateral meetings, providing further detail and insight into both our IT organisation as well the specific investments. This further supported the original business plan submission and supporting annexes, which included benchmarking from Gartner which covered 92% of our investments by value.

There are two areas of cost currently captured within the IT & telecoms assessment that we propose should be assessed outside of it.

Firstly, a line of SO property capex included in BPDT 3.08 as “Policy Project/other”. It exclusively covers a small programme of rolling projects to ensure the GNCC (the main gas control room for the UK) is maintained to ensure it remains fit for purpose as a CNI control room and does not create any operational risk. This should have been assessed with other non-IT non-operational capex. The proportionate assessment of those cost of between £8.8m and £24m focused on historic average over the RIIO-1 period applied to identify reasonable RIIO-2 costs. As per table 3.08 of the BPDT RIIO-1 expenditure of £5.0m gives an annual average of £0.625m. The RIIO-2 cost is £2.6m give an annual average of £0.52m. We have submitted a commensurate and in fact challenging future cost. We highlighted this to Ofgem during the consultation period and provided requested data as contained in NGGT Annex GNCC Capex.

Secondly, two IT investments to fund the IT System impacts of Legislative and Regulatory Change. Regulatory Driven Gemini System Enhancements (GB & EU) and GSO Regulatory and Market Driven changes (Non-Gemini). We anticipate a significant amount of industry change as we move into, through and beyond RIIO-2. With an increased focus on decarbonisation of the energy sectors in which natural gas has traditionally met the energy demand, through EU or UK policy drivers or changing industry trends. However, the direction and speed of change affecting gas markets and efficient operation for end consumers, are all uncertain and this lack of certainty requires us to be flexible. We believe that a pass-through uncertainty mechanism would be most appropriate to fund the system impacts of legislative and regulatory change aligned with the existing pass-through uncertainty for other Xoserve costs. We fully outline this proposal in NGGT Annex RIIO2 Ofgem DDs System Impacts of Regulatory Change Response.

Other non-operational capex

Post publication of the Draft Determination, we have received further clarity from Ofgem in relation to proposals for non-operational Capex baseline funding for STEPM, Non-operational property and vehicle fleet investment. This response is based on this additional clarity, provided bilaterally by Ofgem and summarised below.

1. That the proposed baseline funding is as per the NGGT Annex and not the GT sector document (which contained a different value);
2. That the proposed costs removed and subject to Stage 3 penalty in NGGT Annex, paragraph 3.394 has been miscalculated; and
3. That costs assigned as high or low confidence are as per the NGGT Annex and not as shared bilaterally in the “GT BPI v1.1” Excel spreadsheet

Ofgem has proposed reduced baseline TOTEX for STEPM, non-operational property and vehicles, our views on each of these is provided below:

Table NGGT37 – GTO Non-Op Capex excluding IT

Area	Category	Submission (£m)	DD (£m)	Response (£m)
STEPM	Strategic spares	14.43	12.81	14.03
STEPM	Non-strategic spares	9.51	9.51	9.51
Property	Building refurbishment	[redacted]	[redacted]	[redacted]
Property	EV charging infrastructure	[redacted]	[redacted]	[redacted]
Vehicle fleet	Internal Combustion Engine	6.52	3.87	6.52
Vehicle fleet	Electric (EV)	2.25	2.17	2.17
Total		**44.81**	**39.58**	**43.60**

STEPM

Ofgem proposed disallowing £1.62m for small tools (strategic spares) due to a minor reporting error and provided a breakdown of their view. The breakdown shows that Ofgem have taken our 4 years of historic data and divided it by 5 to give an annual RIIO-2 figure. This is a clear error of computation. We do not accept Ofgem’s proposal to disallow this investment as this does not accurately reflect the costs required for small tools.

Non-Operational Property.

Ofgem has bilaterally provided further information on the four sites where Ofgem did not support our proposed investment (with two specific exemptions). We do not accept Ofgem’s proposal to not invest in these sites. Churchover, Felindre and Kirriemuir require welfare facilities such as disabled access, and the costs for this is £[redacted]k per site, and includes repurposing space, toilets, mess rooms and changing rooms. These costs are produced by Pick Everard, a third-party company.

The refurbishment at Hatton control building is still required but the associated property funding request is now included in our Hatton EJP. In the last ten years a new compressor was installed at Hatton, but no refurbishments were carried out at the control building. As per the Hatton EJP submitted in August 2020, to meet health and safety requirements a heat shield needs to be installed and the fabrication of the building needs to be enough to support the installation. The costs of installing a heat shield and the refurbishment of the building is £[redacted]k and the request for this allowance is included in the Hatton project cost on Greenfield. Refurbishment of control building would not be required on Brownfield as a new control building would be constructed at appropriate distance from machinery.

Internal Combustion Engine Vehicles

Ofgem have disallowed £2.65m for internal combustion engine vehicles and have provided a breakdown of their calculation. Ofgem have taken an average of 8 years using RIIO-1 actuals and RIIO-1 forecast for their proposal, taking 70% of these costs for vehicles that are remaining as ICE due to 30% of vehicles moving to EV’s. We do not accept this disallowance due the following:

- During RIIO-1, the total number of vehicles fluctuated over the 8-year period including a movement of 68 company cars to fleet vehicles. Using the average of RIIO-1 does not reflect the increase in the vehicles over that period, and the starting volume of vehicles for RIIO-2 should be the closing volume of vehicles in 2021.

- We require an additional 22 vehicles in RIIO-2 as outlined in our business plan, 8 for cyber technicians and 14 to support increased project work. This is in line with the requested opex spend for FTEs in these areas.
- Ofgem's calculation for ICEs takes 70% of costs from RIIO-1 rather than volume. This is not a correct reflection of the expected RIIO-2 costs for ICEs as only the lower cost light commercial vehicles will be being replaced with EVs. Taking 70% of costs assumes that higher cost vehicles such as HGVs, 4x4 and large panel vans (with onboard power) will also have some vehicles replaced by EVs. However, there is no EV solution commercially available in the current marketplace for these types of vehicles.

We have provided detailed bottom up evidence in our SQ responses including historic actuals and forecasts on how the business plan submission figures were computed. This methodology includes the above points. Please see 'NGGT Annex Fleet Growth' spreadsheet providing this breakdown and updated vehicle terminology.

Therefore, we believe the current DD allowance understates the costs we expect to incur and that our submitted business plan is an accurate reflection of our expected spend.

Other costs

NGGTQ30. Do you agree with our proposed allowances for Physical Security Capex and Opex?

Table NGGT38 - physical security costs

Capex/Opex	Category	Submission (£m)	DD (£m)	Response (£m)
Capex	New Sites	48.54	26.46	26.46
Capex	Asset Refresh	23.54	5.02	7.97
Capex	Major asset health upgrades	25.69	3.36	3.62
Capex	**Physical Security pre adjustment total**	**97.77**	**34.84**	**38.05**
Capex	Efficiency	0.00	-1.51	0.00
Capex	Capitalised Opex adjustment	0.00	-3.60[37]	0.00
Capex Total		**97.77**	**29.73**	**38.05**
Opex	Pre adjustments	35.25	33.70	35.25
Opex	Efficiency	-1.15	-0.58	-1.15
Opex Total		**34.10**	**33.11**	**34.10**
Total		**131.87**	**62.84**	**72.14**

New Sites

We accept Ofgem's Draft Determination position for new sites capex.

Asset Refresh

We welcome Ofgem's acceptance of the need for a rolling asset replacement programme for IT Hardware and Technical Assets. We are the first network company to make proactive plans for PSUP asset refresh given the age of our solutions, with this initiative representing good asset management practice. There is no regulatory precedent for how this category of work should be handled either within or between price reviews. Ofgem's SSMD did not contain any specific guidance on PSUP asset refresh but determined an ex-ante funding approach for physical security expenditure. BEIS does not currently have any guidance with regard to its expectations for PSUP asset refresh, however were consulted on our plans.

[37] Note Ofgem Draft Determination publication stated capitalised opex adjustment £1.13m and total capex £33.70. However, Ofgem subsequently advised there had been an error in its capitalised opex figure. This table represents Ofgem's updated Draft Determination position of capitalised opex adjustment £3.6m and total capex £31.24m.

We welcome Ofgem's acceptance of our unit cost and volume assumptions for these activities. However, we questioned how Ofgem had arrived at its revised Draft Determination allowances. Ofgem acknowledged that due to a misinterpretation, £2.01m allowance for IT asset refresh had incorrectly been omitted from its Draft Determination position. Calculation errors associated with Ofgem's adjustments for GIPs, Project Management and Risk also resulted in the Draft Determination position being £0.94m lower than intended. Our consultation response position is that these errors should be corrected in full resulting in an updated asset refresh allowance of £7.97m.

Cost confidence
Ofgem has classified costs for new sites as high confidence and costs for asset refresh as low confidence (paragraph 3.416). The impact of the low confidence classification is to reduce the overall blended totex incentive sharing factor, and to trigger the calculation of a proposed BPI Stage 3 penalty.

We disagree with the classification of asset refresh costs as low confidence. On the contrary, the unit cost assumptions used in our updated asset refresh cost estimation methodology stem from the same contract backed information sources underpinning costs for new sites, and as such carry the same degree of cost confidence which Ofgem has classified as high. Furthermore, in paragraph 3.410 Ofgem states that it accepts all our unit cost and volume methodology assumptions for both the IT and Technical asset refresh. These costs now form the basis of the Draft Determination award for asset refresh allowances, so for consistency of approach should be classified as high confidence. The totex incentive sharing factor and BPI penalty calculations should be re-run on this basis for Final Determination.

Major asset health upgrades at two sites.
We accept Ofgem's proposed allowances for replacement of IT assets and Technical Assets at these sites, using an approach consistent with that for other sites.

We welcome Ofgem's acceptance of the need to replace gates at both sites. However, we questioned the associated allowances and it transpired that while allowances had been included for pedestrian gates, no allowance had been included for replacement of the sliding vehicle gates at one of the sites. We propose that the baseline allowance for major asset health upgrades should be updated at Final Determination to include £0.26m for vehicle gates bringing the new total to £3.62m. In our NGGT Annex Physical Security we provide further confidential evidence supporting this request in the form of the cost calculations.

Ofgem considered that our proposals to replace the gatehouse at one of the two sites was not sufficiently justified. Since the December business plan submission, we have obtained additional needs case evidence in the form of an independent Advisory Report containing a list of recommendations to bring the site up to meet CPNI guidelines. We propose that, given the CNI categorisation and the significance of the site, the Final Determination should provide a way forward for us to act upon these recommendations within the RIIO-2 period. We propose that the Final Determination should acknowledge the need case for intervention and that the associated allowances should be reconsidered as part of the site redevelopment uncertainty mechanism for this site. This will allow time for us to develop the recommendations into a robustly costed scope of work. In our NGGT Annex Physical Security we provide further evidence and attach a copy of the independent Advisory Report.

Ofgem has proposed to reject in full the replacement of certain fencing and cills at the two sites, on the basis that the condition data seen to date is not sufficient to justify the investment. Instead Ofgem has suggested that the maintenance (opex) allowance should be sufficient to manage ongoing issues with these assets.

We remain concerned that an opex-only approach may not be the most efficient asset management approach for these fences at sites that may be on the network for several more decades. We agree that further collection and assessment of actual condition data is appropriate to inform detailed scope and preparation for spending commitments. We planned to have detailed independent intrusive condition assessment surveys carried out and to update Ofgem accordingly. However, this survey work was interrupted by COVID-19 lockdown and site access restrictions, meaning we do not yet have the requisite additional information.

We also note that there is a strong long term need for the two sites in question to meet customers' Network Capability requirements. Both sites have already been made the subject of proposed bespoke RIIO-2 reopeners/UMs. Given the current circumstances, our proposed way forward is that the need case for capex interventions on the fences is deferred for consideration as part of the uncertainty mechanisms for these sites. That would allow more time for the condition data to be collected and would ensure that decision making around major project investments at these sites takes proper account of the associated civil security costs looking over the same time horizon.

Our updated indication of the total value (fences and gatehouse combined) for reconsideration as part of RIIO-2 uncertainty mechanisms is £8.65m.

Capitalised Opex adjustment
Following engagement with Ofgem through the consultation process Ofgem agreed that capitalised opex adjustments totalling £77m had been incorrectly applied to net capex costs rather than costs inclusive of capitalized labour; effectively resulting in negative allowances of £12m for our indirect capital activities. Ofgem have agreed to remove this disallowance in their Final Determinations.

Physical Security PCD
We had proposed in our business plan a PCD for the full scope of our proposed physical security capex work. i.e. this would have covered all the relevant scope at new sites, plus asset refresh and major asset health upgrade activities. Our proposed package could be characterized as "higher up-front award, total PCD clawback protection". This would have provided appropriate protection for consumers. For example, if allowances for fence replacement were not spent because detailed site surveys and scoping revealed a lower volume of work necessary than had been allowed for, then the PCD would have operated to return unused allowances to consumers.

In its Draft Determination, Ofgem does "not consider a PCD necessary for the asset refresh or major asset health upgrades to sites given the small amount of funding we propose to allow. Therefore, we propose the PCD is only for the PSUP upgrades at new sites". Ofgem's way forward represents an alternative regulatory package to that which we proposed. Ofgem's proposed package could be characterized as "lower up-front award, partial PCD clawback protection" and this also protects consumers.

While we are content to proceed on the basis of Ofgem's PCD approach, we do not consider that adoption of the "lower up-front award" part of this package should give rise to a BPI penalty for NGGT. Please see our further response on BPI below.

BPI Stages 3 and 4
Ofgem's proposed adoption of a different package of capex allowances without PCD for asset refresh and major asset health upgrades gave rise to a proposed £40.86m cost reduction subject to stage 3 penalty.

Table NGGT39 - Physical Security Cost Confidence

	Ofgem Draft Determination Position		NGGT Consultation Response Position	
Cost Line	Confidence	Costs subject to Penalty (£m)	Confidence	Costs subject to Penalty (£m)
New Sites	High	0	High	0
Asset Refresh	Low	40.86	High	0

We disagree that Ofgem's proposed package of capex allowances should give rise to any BPI penalty at all. Such penalty is wholly unjustified and disproportionate on the following grounds:

- **First of a Kind activity.** We are the first network company to advance proactive PSUP asset health plans and should not be penalised for attempting to do so. This represents good asset management practice. There is no regulatory precedent for handling this new category of spend. We attempted in good faith to accommodate this category of spend in a manner compliant with Ofgem's SSMD decision of May 2019; i.e. baseline allowance plus bespoke PCD.
- **Equivalent consumer protection**. Our proposed package, characterised as "higher up-front award, total PCD clawback protection" although not chosen by Ofgem, would have provided appropriate protection for consumers; unspent allowances for scope deemed unnecessary (e.g in light of survey results yet to be completed) would have been returned to consumers through our bespoke PCD proposal. Ofgem's preference for an alternative consumer protection package, without PCD, is an acceptable way forward but should not manifest as a penalty against NGGT.
- **NGGT voluntary £15.5m reduction.** To the extent reduced up-front asset refresh allowances result from the application of new methodology, this updated forecasting methodology was supplied voluntarily by NGGT. As such, we refute Ofgem's statement in paragraph 3.417 that "NGGT did not provide any further evidence to substantiate the asset refresh costs…" Consequently this £15.5m reduction does not fall within the remit of stage 3 BPI penalty which SSMD paragraph 11.46 defines as pertaining to "costs…removed by Ofgem from the companies' forecasts."
- **New methodology provides high confidence.** Ofgem states in paragraph 3.410 that it supports the new methodology. It follows that the unit cost and volume assumptions now adopted as the basis of award should be classified as high confidence, not low confidence as stated by Ofgem in paragraph 3.416. According to Ofgem's BPI scheme, costs classified as high confidence do not feed into BPI penalty calculation, even if adjusted downward as an outcome of Ofgem cost assessment.
- **Costs transferred from baseline to UM should not be penalised.** It would be unfair to apply BPI penalty in circumstances where COVID-19 lockdown has hampered our efforts to collect and provide additional evidence of asset condition. It would be fairer in the circumstances to transfer the major asset health civils investments £8.65m out of baseline for future consideration as part of the bespoke uncertainty mechanisms for these sites. We continue to work with Ofgem, across all asset health categories, to provide as much asset data as possible and to achieve the most appropriate attribution of costs to baseline or UM in consumers interests.
- **Ofgem calculation errors should not give rise to penalty.** Ofgem's misunderstandings and calculation errors totalling £3.21m should not contribute to BPI penalty.

Physical Security Opex

We accept Ofgem's physical security opex Draft Determination position of a proposed baseline opex allowance of £33.70m. We note that our proposal was £1.68m lower than Ofgem's view of modelled costs and other things being equal should have qualified for BPI Stage 4 reward.

Network operating costs (direct opex)
Indirect costs

NGGTQ31. Do you agree with our assessment approach and baseline allowances for NGGT's Opex costs, including network operation costs, BSC, CAI and Quarry and Loss?

Table NGGT40 - Opex

Opex category	Category	Submission (£m)	DD (£m)	Response (£m)
Operational Costs	Pre adjustments	355.18	345.95	355.18
Closely Associated Indirects	Pre adjustments	211.29	117.61	211.29
Business Support	Pre adjustments	296.49	267.89	296.49
Crop, Quarry & Loss of development	Pre adjustments	17.30	6.89	17.30
	Efficiency	-33.43	-13.78	-33.43
	Total	**846.84**	**724.56**	**846.84**

We do not agree with the assessment approach and baseline allowances, for multiple reasons across each of the categories of opex. Our response takes each sub-category of opex costs in turn and given differences in Ofgem's assessment in each area explains our disagreements, related consumer impacts and remedies needed for Final Determination.

Network Operating Costs (NOC)

We do not agree with Ofgem's proposed disallowance of £9.48m. Allowances for Planned Inspections & Maintenance (PI&M) have been removed from baseline where trend lines fall below submitted costs despite Ofgem stating in the DD that deviations to historical trends have been satisfactorily explained. In setting allowances below modelled forecast costs for Faults Repairs at the same time as reducing our costs for PI&M, Ofgem's methodology does not consider the interdependency between planned and reactive interventions. Ofgem have not adjusted allowances for upward cost pressures relating to our workforce renewal strategy, delivery of cyber operational technology (OT) and other workload factors despite agreeing that we "*provided a satisfactory explanation for any deviations to historical trends*".

Our submission for network operating costs was strongly interlinked with our proposals for asset health interventions. In reducing or deferring RIIO-2 asset health allowances Ofgem's Draft Determination proposals will see the absolute level of risk on the network increasing by 7% over the next 10 years. This will increase our spend on repair and maintenance by 9% over the same period and will materialise fully in RIIO-3.

In making their final proposals Ofgem should:

- Assess Faults Repairs and PI&M costs in aggregate, recognising the interdependency of these activities;
- Make appropriate allowances for our workforce renewal plans, cyber OT and other workload drivers
- Address the remedies set out in relation to our asset health programme as specified in the relevant sections of our response

In addition, we propose Ofgem agrees our proposal to treat baseline costs relating to the Joint Office of Gas Transporters as pass-through.

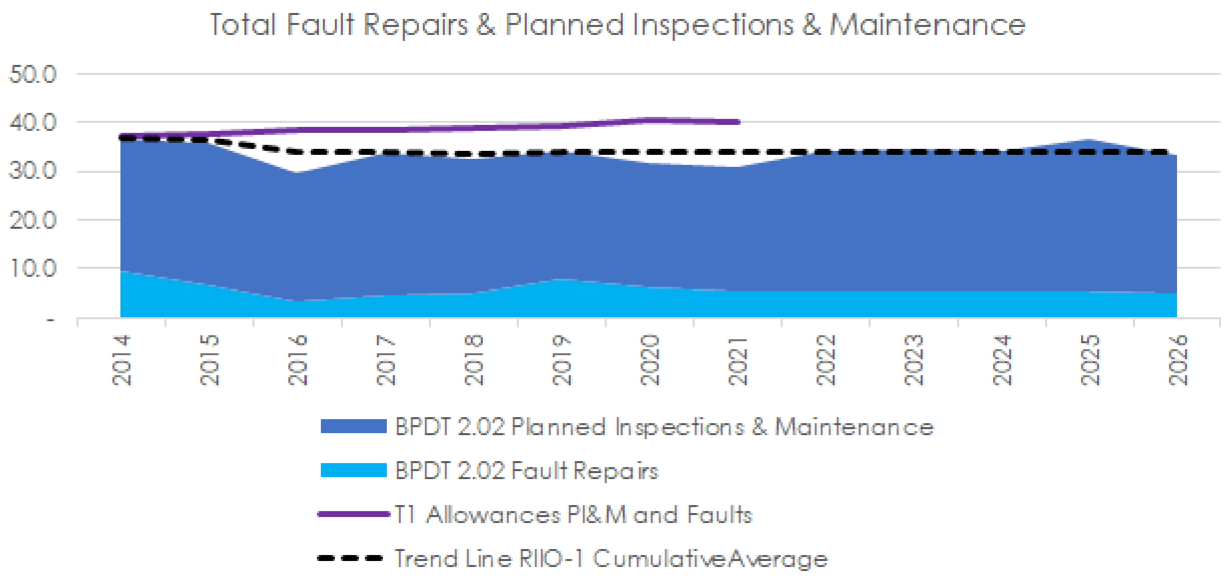
Interdependency between Planned Inspections & Maintenance (PI&M) and Faults Repairs

Ofgem assessed Network Operating Costs on both an aggregated and disaggregated basis, with allowances being awarded in full where the historical trend shows higher costs on a disaggregated basis. Proposed costs for Faults were allowed in full as they were below Ofgem's forecasts, however £9.46m of PI&M costs were disallowed due to Ofgem's model predicting lower costs.

In applying this mechanistic assessment on a disaggregated basis Ofgem miss the interdependency between Faults and PI&M, namely that we plan maintenance interventions in order to keep faults at an efficient level and avoid customer disruption. Our ability to deliver lower than forecast Fault costs is dependent on delivering our planned maintenance programme. Reducing planned maintenance when we also have an aging network, will increase the risk of customer disruption from unplanned Fault Repairs.

Aggregating the two activities and comparing them to Ofgem's forecast costs properly reflects the interrelatedness of these two activities and reduces the difference to Ofgem's forecast from £9.46m to £4.68m.

Figure NGGT41 – Combined PI&M and Faults costs versus RIIO-1 allowances and historic cost trend



<u>Ofgem's determination does not include allowances for upward trends despite agreeing their satisfactory explanation</u>

The net £4.68m increase in combined Fault Repairs and PI&M costs is explained by upward cost drivers of £8.6m detailed in our business plan. Ofgem state that these have been assessed and understood within the Draft Determination consultation document but their determination does not include allowances for them. We presented evidence for three cost drivers, which we summarise here.

Workforce renewal - £2.0m over the RIIO-2 period (£0.4m p.a.)

Our strategic workforce planning process has identified that 19% of this workforce are due to retire in the period 2020-2030 with a combined length of service of 628 years. Action through RIIO-2 in recruiting and training apprentices and semi-skilled engineers will pre-empt the loss of experienced personnel maintaining workforce resilience. The additional headcount and training costs will result in an average £2.7m per year increase, £0.4m of which is within our direct workforce and the remaining £2.3m of which relates to closely associated indirect costs.

Cyber OT - £4.0m over the RIIO-2 period (£0.8m p.a.)

8 FTEs providing first and second line fault response, incident handling, training and emergency preparedness exercises approved for NIS works across the NTS. This is a new area of work and we have been discussing with Ofgem moving these costs to be included within our cyber allowances.

Workload driven - £[redacted]m over the RIIO-2 period (£[redacted]m in FY25)

Remediation of faults found on the Mickle Trafford to Deeside section of Feeder 21 following the PSSR inspection which we propose to complete by external inspection. We provided additional evidence on this activity to Ofgem during their review of our business plan in which we indicated that latest cost estimates indicated £[redacted]m, compared with the £[redacted]m that we originally estimated. In their Final Determinations Ofgem should recognise the interdependencies of fault and PI&M activities and assess our costs for these activities in aggregate. Ofgem have already satisfied themselves with the evidence we have provided for upward cost pressures in RIIO-2 and we ask that they adjust allowances in their Final Determination to recognise this.

Proposed treatment of Joint Office of Gas Transporters costs as pass-through
We propose that the costs of the Joint Office of Gas Transporters should be pass through costs. Joint Office costs are largely driven by the number of modifications raised and their complexity, this is only partly controlled by the Transporters as Shippers raise approximately 50% of modifications (24 out of 45 in year to June 2020). Some of the modifications raised by Transporters are driven by regulatory change such as faster switching that is also out of Transporter control.

At the time of submitting our business plan in December 2019 we were expecting, based on statements made, a response from BEIS / Ofgem to the Code Governance Review consultation responses in January 2020. This review is now stalled; however, based on comments made by Ofgem both at UNC modification panel in July 2020 and in meetings with the Joint Office during 2020 we anticipate Ofgem to ask Transporters to move the Joint Office from its current Code Administrator role towards a Code Manager role without a regulatory decision.

We are willing to facilitate this move to deliver customer benefit and better industry governance conditional on our exposure to unfunded additional costs being mitigated. We propose pass-through treatment as being appropriate for Joint Office costs. Whilst we recognise this proposal is new we believe that it is reasonable given that the Code Governance Review will not deliver a conclusion until after the start of RIIO-2. We are keen to work with Ofgem to enable this to be included in the Final Determinations.

Closely associated indirect & Business support costs
We do not agree with Ofgem's proposals for indirect cost allowances. Ofgem's decision to disallow £93.6m Closely Associated Indirects (CAI) costs and £28.6m Business Support Costs (BSC) is based on unreliable regression models that incorrectly assume comparability between Transmission companies despite significant differences in scale and nature, are highly sensitive to modelling decisions and do not statistically support the rejection of our submitted business plan costs as inefficient.

Retaining this decision at Final Determinations will result in 60% reduction in funding for our ongoing opex activities to support the network, significantly limiting our ability to deliver mandatory activities such as maintaining compliance with our safety case and legislative environmental compliance including the operational training of our field force and retaining the engineering expertise to assess network risk. It will also hugely reduce our ability to provide skilled engineering expertise and strategic leadership to support net-zero through hydrogen as well as risk the effective implementation of our stakeholder and digitalisation strategies.

Whilst regression models can be useful within a broader toolkit of approaches to help Ofgem form a view of expected future costs (for example as in RIIO-T1 for business support cost benchmarking), inherent limitations in the approach as it applies to indirect Transmission costs make it a fundamentally unsafe basis on which to set allowances, this is acknowledged over six separate times by Ofgem's own consultants in their report. Our key issues are summarised below.

Allowances have been set based on observations from only six years of RIIO-1 costs for the four Transmission networks, resulting in a wide dispersion of apparent efficiency gaps because there is not sufficient data to reliably estimate efficient costs.

The regression approach incorrectly assumes comparability between the three Electricity networks and Gas network companies despite being widely different in scale and, for Gas, nature and in so doing leads Ofgem to disallow efficient forecast costs.;

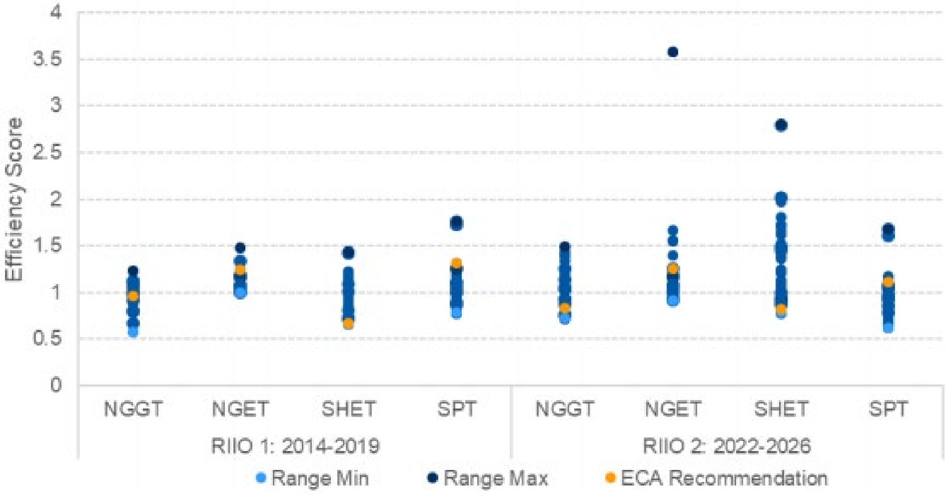
Ofgem's preferred models fail important statistical tests and so are subject to error and bias in their estimation of true efficient costs, leading to disallowances that are too high.;

The coefficients used by Ofgem to set allowances are highly sensitive to modelling decisions around the treatment of scale and selection of cost drivers making it impossible to conclude where the true efficient view of costs lies, for example by selecting alternative modelling approaches that still meet Ofgem's model selection criteria the efficiency score for NGGT CAI costs in RIIO-2 could fall anywhere between 0.72 to 1.49.

Ofgem has used the results from these models directly to set allowances and has failed to consider evidence we submitted to demonstrate the efficiency of our underlying costs. This is particular concerning in cases where we forecast increases in cost drivers, such as rising insurance premiums and support for cyber, BAU innovation, environment and net zero activities.

In adopting this approach for the first time to assess Transmission indirect costs Ofgem have gone against their stated intent to "adapt the RIIO-ET1 cost assessment process, as appropriate, rather than establish a new approach for RIIO-ET2". Earlier engagement on indirect cost assessment methodology, for example as part of the RIIO-2 tools for cost assessment consultation in August 2019, would have helped Ofgem gather views from networks and other stakeholders and develop a more robust cost assessment methodology than the one they have relied on in their Draft Determinations.

Figure NGGT42 - Efficiency scores for CAI across a range of models that pass Ofgem's model selection criteria



Source: NERA analysis. Note: We illustrate the efficiency score for NGGT implied by ECA's modelled and prior to Ofgem's adjustment.

Notwithstanding these fundamental issues, our submitted business plan costs fall within the confidence interval of efficient costs predicted by Ofgem's preferred models, and so should not be rejected as inefficient.

We set out our view of the errors of methodology and principle in Ofgem's determination in more detail below. In making their Final Determination Ofgem should exclude NGGT from regression analysis with ET sector, recognising that NGGT does not have comparable cost structures to the ET sector. Ofgem should instead place greater weight on evidence submitted by NGGT for the efficiency of our proposed expenditure in RIIO-2. For our net CAI and BSC costs this would mean assessing our proposed costs against historic performance and external benchmarking evidence and the justification we have provided for the upward cost pressures we foresee in RIIO-T2. For indirect capitalised costs this would mean assessment as part of the capex cost assessment process. On the basis of such a review we would expect Ofgem to allow our submitted costs in full.

We have identified errors in the calculation of indirect allowances which we have agreed with Ofgem:

Following engagement with Ofgem through the consultation process Ofgem agreed with us that capitalised opex adjustments totalling £77m had been incorrectly applied to net capex costs rather than costs inclusive of capitalised labour; effectively resulting in negative allowances of £12m for our indirect capital activities. Ofgem have agreed to remove this disallowance in their Final Determinations.

Following our review of the econometric models used to model CAI allowances we identified that the historic and forecast capex figures used to predict CAI costs were incorrect. Ofgem provided corrected capex figures to us which we estimate would result in a £51m increase in predicted CAI allowances.

As a result of seeking to understand how Ofgem's determinations had resulted in the given allowances Ofgem identified errors totalling a £2.7m increase in CAI allowances from their determination, and £1.0m increase in BSC allowances which they have agreed to correct in their Final Determinations for BSC.

Ofgem's models have poor statistical fit

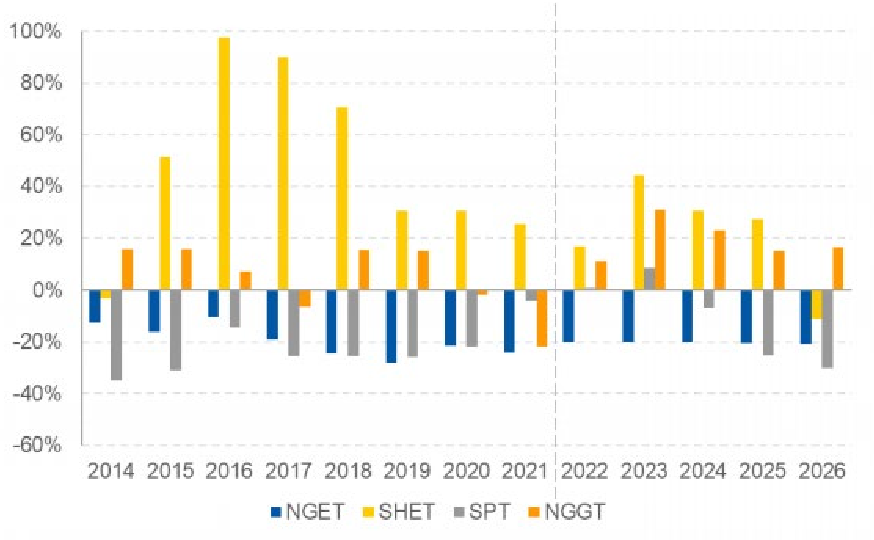
As we set out above, we fundamentally disagree with Ofgem's decision to set allowances for indirect activities based on a regression model approach that seeks to compare the costs of fundamentally different networks, is highly sensitive to modelling decisions and statistically flawed. We set out our reasons in support of our position in more detail later in our response.

However, in our assessment of Ofgem's determination we have sought to understand the approach taken by ECA in providing a view of efficient costs. We asked NERA to perform a detailed review of ECA's approach to modelling indirect costs and their report, "Opex cost assessment" is submitted alongside our response. NERA found a number of significant flaws with ECA's preferred statistical models for CAI and BSC which they set out in detail in their report and we summarise here in turn.

Ofgem's consultants, ECA, set out in their report the model selection criteria used to identify preferred models. Their phase I selection criteria focuses on the reliability of the modelled coefficients above considerations such as the overarching fit of the model and therefore the model's ability to explain efficient costs. However, despite having selected preferred models that pass the selection criteria on a number of occasions throughout their report ECA note the wide dispersion of coefficients for SPT in the BSC model and for NGET and SHET in the CAI model, in particular.

NERA analysed the differences between historic or forecast costs and Ofgem's modelled costs for both BSC and CAI finding for example in the CAI model, apparent inefficiencies of between 10-20% for NGET over the RIIO-1 period and underspend of over 50% for SHET for individual years of the same period (see chart below). NERA concluded that these are "wider than can credibly be ascribed to differences in the TO's relative efficiency" and that "this extremely poor fit … means that it is likely there are other important drivers for which ECA has not controlled, the assumed functional relationship is wrong, there is not sufficient data to reliably estimate relationships … or, more likely, all these problems apply."

Figure NGGT43 - Difference between modelled and actual/forecast CAI costs as a percentage of actual/forecast CAI costs



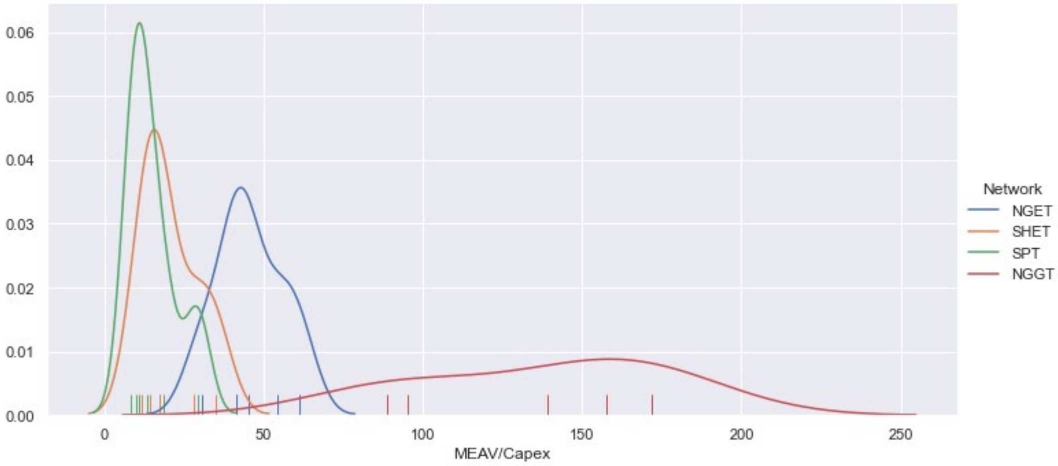
Source: NERA analysis of Ofgem's Cost Assessment File

Ofgem have set allowances based on an approach that incorrectly assumes comparability between Transmission businesses

The cost assessment approach taken by Ofgem is underpinned by the assumption that the relationship between driver and cost is of a comparable nature for each of the networks assessed. In their report ECA point to the comparability of reporting across the GT and ET sectors as a justification to support pooling of these sectors, and also notes that CAI trends are broadly comparable across the three ET companies, though GT is divergent. However, comparability of cost reporting and trends over time do not in of themselves support the pooling of these two different sectors with widely varying network companies. Discounting these two observations leaves Ofgem's approach lacking any justification as to why, for the first time, it is appropriate to pool Electricity and Gas transmission companies together for the purpose of determining efficient costs.

We examined whether there was evidence of different relationships between CAI costs and MEAV and capex cost drivers in two separate ways. Firstly, we looked at the distribution of MEAV and capex for the four transmission networks. The density chart below shows clearly that the distribution of MEAV over capex for National Grid Gas Transmission is very different from Electricity Transmission networks. Two sample Kolmogorov-Smirnov tests confirm that National Grid Gas Transmission distribution is indeed not statistically comparable to Electricity Transmission networks.

Figure NGGT44 – Historic ratio of MEAV over capex for the four Transmission network companies



Secondly, we asked NERA to model alternative combinations of Ofgem's preferred CAI and BSC models, including looking at dummy variables and interaction terms. NERA found GT dummy variables and interaction terms with cost drivers were all significant, indicating that there is a significantly different relationship between CAI and Ofgem's selected regressors for GT and ET showing that the model is mis-specified. NERA were able to demonstrate similar issues with ECA's preferred BSC model also, despite the inclusion of a GT dummy variable in this model. NERA conclude that ECA's preferred CAI model is not accounting for the different relationships between networks CAI and so is mis-specified and cannot be relied upon to forecast TO costs over the RIIO-2 period. NERA were able to demonstrate similar issues with ECA's preferred BSC model also, despite the inclusion of a GT dummy variable in this model.

In relying on models that incorrectly assume a common relationship between cost drivers and costs across the Transmission companies to set allowances, Ofgem are disallowing costs because they are not predicted by this model as being efficient when in fact they may be efficiently incurred as a result of other drivers. For Final Determinations Ofgem should remove NGGT from the regression analysis on account of different relationships for CAI and BSC costs than the ET sector and instead assess NGGT CAI and BSC costs on the basis of our submitted evidence.

ECA's preferred models fails important specification tests and so may over or under estimate efficient costs

ECA reports that their preferred CAI and BSC models fail two important test of model specification:

1) **The Ramsay RESET test** – which determines whether a model properly accounts for non-linearities between the selected cost drivers and modelled costs, resulting in biased coefficients that will under- or over-state network's predicted costs. ECA acknowledge this result but downplay the importance of this test in their report, however this stands in contradiction to economic practice and Ofgem's own recognition of this test as key in RIIO-ED1 Final Determinations.

2) **Breusch-Pagan test and Hausmann test** – indicating that alternative model forms may be more robust than ECA's preferred POLS model for both CAI and BSC. ECA considered alternative model forms but dismissed them on the basis that their results were "implausible", preferring "a POLS model to be more reliable in a small sample setting". Whilst POLS is more able to cope with small sample sizes, its failure on these two critical tests means that the resulting model coefficients are inefficient and, in the case of CAI, also biased. ECA's observation that the coefficients from alternative models are implausible is not appropriate justification to select POLS, rather it points to the model specification being wrong or there being too little data to reliably estimate indirect costs for Transmission companies.

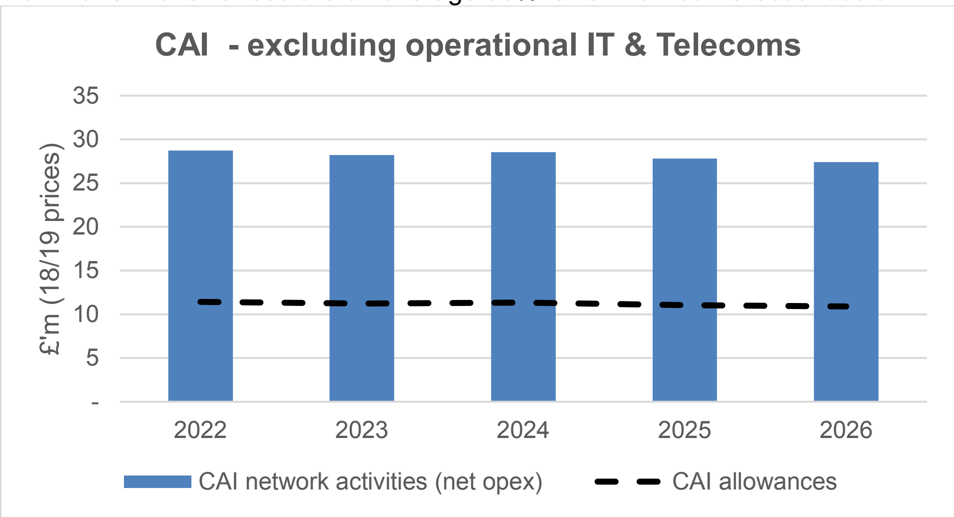
Whilst we disagree with the classification of these tests as not of high importance, we recognise that alternative FE and RE models suggested by the failure of these tests are less able than POLS to deal with the small number of observations that ECA has been asked to model and we show below that the modelled coefficient is highly sensitive to the choice of model form. Notwithstanding our view that NGGT should not be assessed within an ET sector regression model, our evidence here emphasises the caution Ofgem should adopt when relying on the results of sector regression analysis, and the importance of considering other evidence outside of the modelling process in reaching a Final Determination for allowances.

The cost drivers used to predict efficient CAI costs do not adequately explain our costs
Ofgem chose to analyse CAI costs at a totex level, stating "otherwise, a model's assessment may be unduly influenced by differing cost allocation policies". In their report, ECA acknowledge this decision to model as totex prevented CAI from being split into fixed and flex components as was

considered for ED1. Their modelling approach included MEAV as a driver to capture scale effects and to smooth the bumpiness of year on year fluctuations in capex drivers.

In their concern about potential noise from capitalisation policies Ofgem failed to recognise the significant level of activities reported in CAI that are not in support of capital workload, but instead relate to the safe operation and ongoing operation of our network. 78% of the net CAI costs we include in our RIIO-2 submission directly relates to the delivery of our safety case and other obligations, with the remaining 22% of costs relating to Network Engineering and Design activities (including work to support net-zero, hydrogen and digitalisation strategies), non-capitalisable project management activities and an element of OMGS that cannot be directly ascribed to primary safety activities. Failure to adequately model these costs has resulted in a disallowance of 60% on net CAI (excluding operational IT & Telecoms) which would trigger material changes to our safety case that would require acceptance by the HSE.

Figure NGGT45 - Net CAI allowances are on average 60% lower than our forecast costs



Note: Net CAI allowances adjusted for information received from Ofgem following Draft Determination

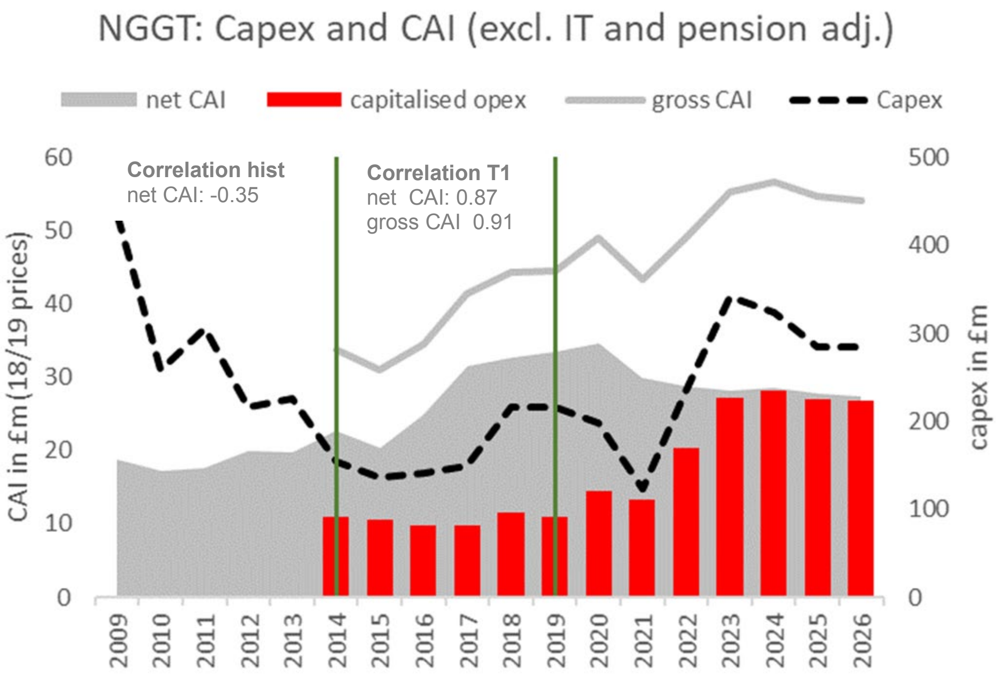
In making their Final Determination Ofgem should assess the costs of the ongoing operation of our network separately from indirect capital costs, recognising that these activities are not driven by capital workload. Indirect capital costs should be assessed as part of the capex cost assessment process.

Limited observations incorrectly support a stronger correlation between CAI and capex than in reality

Ofgem point to analysis that ECA performed splitting CAI into primary and secondary groups and observing similar relationships between capex and both groups of CAI costs as justification for using capex as the primary cost driver. However, examination of our RIIO-2 forecasts and data from TPCR4 show that this apparent correlation between net operating costs and capex is not observed outside of the six years of actual cost that Ofgem used to model costs. Net operating costs rose through the early part of RIIO-1 as we identified a need to enhance the asset and condition data of our network in order to better inform asset health interventions going forward, the impact of which on allowances has been reported to Ofgem every year as part of our RRP submission. This happened to coincide with a rising profile of capex through RIIO-1 in part responding to an increase in asset health works but also driven by periodic reopener mechanisms funding significant capital projects.

Ofgem state that concerns about the comparability of prior price control data was such that they were only comfortable relying on the six years of historic data from RIIO-1 (across 4 networks equating to 24 observations in total). We recognise the challenges in working with historic data, however given the decision not to consider fixed and flex elements of CAI, Ofgem and ECA should have done more to test the robustness of the observed associations over a greater range of observations and could have performed the simple data checks that we ourselves performed as cross check on the output of a model based on RIIO-1 data. In failing to do so, ECA has selected a primary cost driver that fails Ofgem's own criteria for cost drivers to "have relatively stable relationship with costs over time".

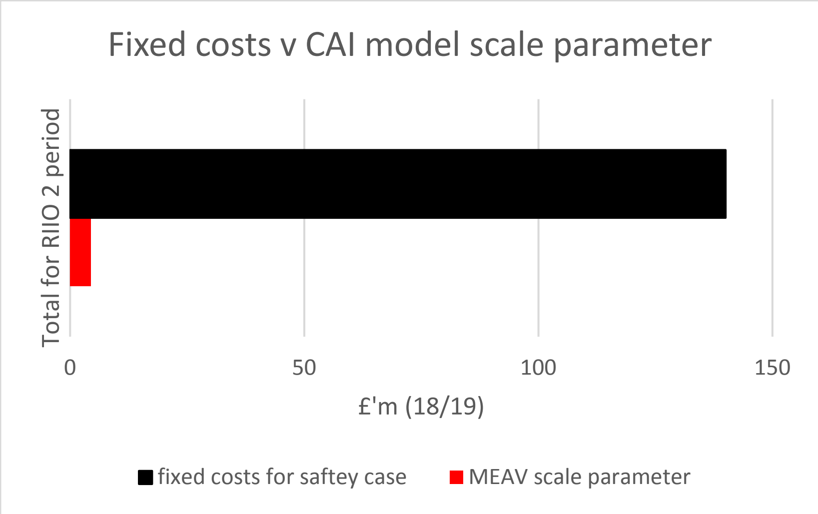
Figure NGGT46 – Historic and forecast net and capitalised CAI costs and capex expenditure. A positive correlation is not observed for net CAI outside of the six years of actual RIIO-1 expenditure



MEAV driver is a weak predictor of our operating costs in the CAI regression model

ECA include MEAV as a secondary driver in the CAI model to account for scale differences between networks' operating costs, however our own analysis casts concern over the strength of MEAV as a driver. We used the modelling data provided to us by Ofgem to replicate the CAI model in order to understand what costs are predicted by the MEAV driver alone (which we did by setting the value of the capex driver to 1.00). Our modelling suggests that the MEAV driver predicts an additional £1m per annum of cost to support ongoing operations of the network against our business plan submission of an average £28m per annum for the same activities. This is not unexpected given that in ECA's models the coefficient for MEAV in their preferred model is 0.231 compared with the capex coefficient of 0.754. It is evident that MEAV is not adequately differentiating between networks scale-driven costs with the consequence ongoing net indirect operating costs are inadequately predicted and our forecast of costs above this prediction are presumed to be inefficient.

Figure NGGT47 - Fixed costs in BP are not accounted for by the CAI regression model scale parameter utilising MEAV data



ECA used a log-log specification for all their models to enable the resulting coefficients to be directly interpreted as elasticities, i.e. a 1% increase in the cost driver translates to an X% increase in costs. However, in using the log of MEAV as a cost driver we believe ECA have effectively attenuated the ability of MEAV to capture scale; this is corroborated by analysis performed by NERA as part of their identification of alternative model forms, who found running the CAI regression model without the log of MEAV more closely predicted NGGT and other network submitted CAI costs.

We note as a point of process that NGGT was requested to provide MEAV data within the BPDTs on 8th October without knowing how it would be used in the cost assessment process, and at no point before Draft Determinations did Ofgem engage with us to discuss with us or other networks what limitations might be present in the measure. The MEAV calculations we provided were to the best of our ability and based primarily on network data we use as part of our insurance premiums process. Through engagement with Electricity Transmission networks we understand them to have taken a different approach in calculating MEAV. Ofgem have stated that they have been able to trace the source of MEAV calculation inputs to the BPDTs and satisfy themselves that the calculations are broadly comparable. However, NGGT BPDTs are in a different format to those of Electricity Transmission networks and so it is not clear to us how Ofgem have reached satisfaction in this regard.

The Gas network is aging, with old and in some cases obsolete assets. Maintaining these assets, for which full replacement is not always cost justified, requires complex, risk-based asset decisions for which we employ specialist engineering resources from across a wide range of disciplines. Contrary to ECA's assumption that the challenges in managing the network fall with falling gas demand, challenges increase as gas flows are becoming more unpredictable and volatile (as a result of supporting, intermittent renewable electricity generation) even though gas demand overall is falling. In addition, as we have highlighted elsewhere in our response, Ofgem's funding of our asset health capital programme to below RIIO-1 levels will result in a 7% increase in absolute risk on the network over the next 10 years further increasing the need for specialist engineering resource to manage the network effectively.

The legislative compliance requirements for Gas are distinct in scale and nature from other sectors. As an example, under Gas Safety (Management) Regulations (GS(M)R), National Grid Gas are required to have a safety case demonstrating compliance which has been accepted by the HSE in writing. The requirements of the safety case are set out in schedule 1 of the Regulations and include:

- Operational and maintenance procedures
- Safety management – Risk assessment, health and safety arrangements, monitoring of health and safety performance, competence and training and audit

- Emergency response arrangements

Any material change to the NGGT Safety Case needs to be accepted by the HSE before implementation in accordance with GS(M)R Regulation 4 (2). In addition, our terminals at Bacton and St Fergus are upper tier COMAH sites. Under COMAH, we are required to submit a COMAH safety report every 5 years to the competent authority (HSE and environmental regulator) and, should deficiencies be identified, regulators can prohibit use of the site.

We also have environmental obligations that are funded through our CAI allowances:

- Under the Environmental Permitting Regulations (England and Wales) and Pollution Prevention and Control Regulations (Scotland), National Grid Gas Transmission have several permit obligations which are included within our CAI submission:
- Ensuring environmental operations are resourced and competent to an appropriate level with adequate controls in place to mitigate the risk of pollution
- Mobile periodic emissions monitoring across our compressor fleet required to ensure continued compliance and operation (included within other materials goods and services under Engineering, Management and Clerical.)
- Regular monitoring and reporting of emissions (to air, land and water) on a near constant basis (daily, weekly, monthly, quarterly, annually)
- Responding to environmental incidents and emergencies

Some other key areas of our CAI submission include:

- Operational Vehicles and Transport: these costs are largely dependent on the number of operational resources and hence operational fleet, for which the majority of funding has been allowed by Ofgem in the Draft Determination. These costs are also related to the size and geography of the network we maintain and operate which is not changing during RIIO2. They are a key element of compliance with our safety case. These costs had no capitalisable element in our business plan submission.
- Operational Training: A key part of our safety case is having a competent operational workforce. The training requirement is largely dependent on the number of operational resources for which the majority of funding has been given by Ofgem in their Draft Determination.
- Specialist Engineering Capability: The ongoing efficient maintenance of the gas network relies on specialist engineering capability across all the key engineering disciplines; mechanical, electrical, civil as well as specialist skills in areas such as welding, corrosion, safety and risk assessment and environment. In RIIO-2 this expertise will also need to be applied to our net-zero challenge, in particular the safety and operational implications of putting hydrogen and hydrogen blends into the network.
- Digital Capability: In our latest re-organisation we created a Systems, Data and Analytics team for GT. This team leads and supports GT in continuing to develop and implement our digitalisation strategies; including improving business access to data and the quality of data.
- Stakeholder Engagement: During RIIO-1 and as part of our RIIO-2 business plan development we have gained huge insights and benefits from engaging with our stakeholders on their requirements. These activities are becoming business as usual for us with a small number of dedicated stakeholder FTE's being supported by a wide range of business teams (typically those funded through our CAI allowances) in delivering stakeholder engagement and then feeding insights into our future business plans. Ofgem propose a reputational incentive for this in RIIO-2 against which we will need to report.

ECA sets out Ofgem's three cost driver criteria in their technical report, one of which is the need to "incorporate as much relevant information as possible" to "help[s] distinguish between costs which are explained by differences in exogenous conditions and costs which are explained by differences in efficiency". Neither the capex nor MEAV driver adequately capture information about the complexity of activities required to support the Gas transmission network and so the model incorrectly ascribes these costs as inefficient. In making their Final Determination Ofgem should place greater weight on the evidence we submitted for the efficiency of our proposed expenditure in RIIO-2.

Ofgem have not considered future changes in cost drivers

Our CAI submission also included requests for funding for new or increasing activities. These include:

- **Environment:** Development of science based environmental targets is a key part of us reducing our impact on the environment in the most cost-effective way. We have requested funding of £0.7m in FY22 for this work (included within Network Policy (inclu. R&D))
- **BAU innovation**: A small team to explore and lead the implementation of new technology and techniques to drive the future efficiency of our business (included within Network Policy (including R&D). This results from Ofgem's proposed NIA changes in RIIO2.
- **Net-zero**. Within our December plan we have a small number of FTE's allocated to net-zero and hydrogen. Working with BEIS and other network companies, the pace of change in this area has accelerated significantly since December, and we are needing to do more to assess the potential of hydrogen in the GT Network.
- **Cyber**. Within our December plan £2m costs for 4 additional CAI FTE's were requested. These are to provide technical support to the current and future Cyber programmes of work. These resources will also prepare and coordinate future Cyber reopeners. This is a new area of work and we have been discussing with Ofgem moving these costs to be included within our cyber allowances.

In addition, since December and as a result of the DD there are additional upward cost drivers to our plan:

- In DD Ofgem have also placed a **new licence condition** requirement on us to deliver an annual environmental report. The resource required to deliver this is unfunded.
- In DD Ofgem have significantly **increased the number of reopeners** from 7 in RIIO-1 to over 25 in RIIO-2. Much of the preparatory work required for these reopeners is funded by Ofgem in our capex allowances. However, they will incur Opex costs to bring together the information required by the reopeners and to respond to Ofgem SQ's and external consultations. Our December plan assumed re-openers at a similar level to RIIO-1 leaving us unfunded for this additional activity.
- Since our December submission we have been working closely with BEIS on **net-zero and hydrogen**, an area of work that is progressing rapidly. To progress work further will require access to significant engineering expertise above that requested in our December plan.

In their approach to cost assessment Ofgem have not taken into account the true workload drivers for GT. They have failed to fund us appropriately, or consistently with other areas of the DD, for costs required for legislative compliance. An approach based on historic costs cannot take into account the significant transitional change that GT will go through in RIIO-2 as we prepare to enable hydrogen and hydrogen blends in our network, against a backdrop of managing an aging asset infrastructure and changing customer requirements. To deliver our consumer priorities of reliability, affordability and net-zero relies on our specialist engineering resources and access to accurate asset information; both of these currently unfunded through our CAI allowances.

Our business plan included insurance costs of £[redacted]m for the RIIO-2 period, representing an increase of on average £0.7m per annum from RIIO-1. This was driven by changing insurance premiums, the cost of which represent over 95% of our insurance costs. The increase can largely attribute to our property damage (including business interruption) which will rise when the Captive currently long-term reinsurance agreement expires in March 2021.

The reinsurance premium rates have been held broadly flat since 2017 in a market which has experienced significant increase in insured losses globally during the same period. April 2021 represents the first time since 2017 that our reinsurers are able to make premium rating adjustments, which will be accelerated upwards due to the current distressed position of the market generally. Current indications (July 2020) are the property damage reinsurance cost will increase by 25% in FY22. We are hopeful the Captive-let arrangements we operate for National Grid companies can support the operational businesses and not pass through the full extent of the external market increase, resulting in a net impact of c. 12.5% increase in the retail property damage premium charged. In our business plan we provided evidence from two independent insurance brokers who estimated that commercial market premiums for comparable coverages would be over 30% more than our proposed premiums for RIIO-2.

Ofgem excluded insurance costs from their benchmarking assessments in RIIO-1 and ECA also considered insurance costs as a potential “atypical” cost citing evidence of uncertain forecasting or “an expected step change that may be difficult to account for with a benchmark based on historic data.” ECA considered excluding insurance from the econometric modelling having observed step change increases in SHET and SPT forecasts as well as noting more generally, “differing insurance costs may better reflect different risk appetites and / or appropriate insurance coverage levels rather than being an indicator of ‘efficiency’”. We highlight not insubstantial increase of £0.7m per annum in our own costs and also agree with the general point ECA raises.

In making their Final Determinations Ofgem should look to allow the impact of rising premiums on our proposed insurance costs for RIIO-2, recognising that these are efficiently managed through our Captive-led arrangements, as corroborated by two independent insurance broker reviews.

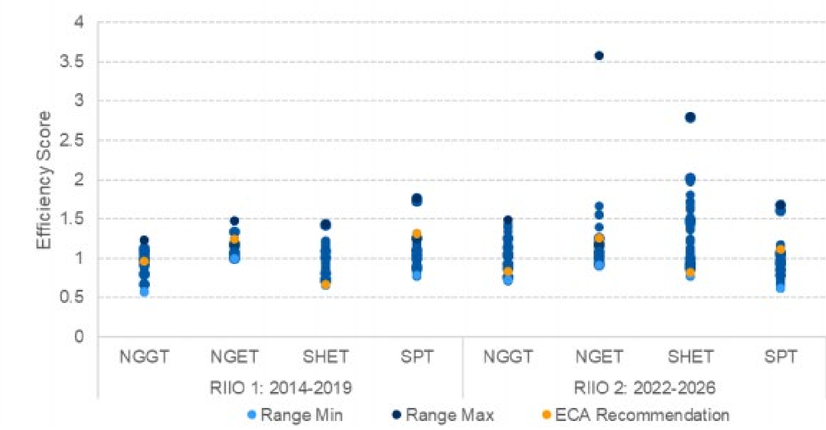
Ofgem’s statistical models are not sufficiently reliable to assess efficient levels of indirect costs

In at least six separate instances throughout their technical report, ECA caution Ofgem against setting allowances directly from their modelling outputs, stating in their conclusion *“the resulting efficiency scores do require further scrutiny from Ofgem, outside of this modelling process, to understand whether an efficiency challenge is appropriate.”* Ofgem do not provide any further detail on how they considered ECA’s advice in this regard, however it is notable that their determinations of BSC and CAI costs and the calibration of the opex escalator mechanism are all derived directly from ECA’s preferred model coefficients.

We asked NERA to identify alternative approaches or model forms that would meet the model selection criteria set out in ECA’s report. NERA looked at:

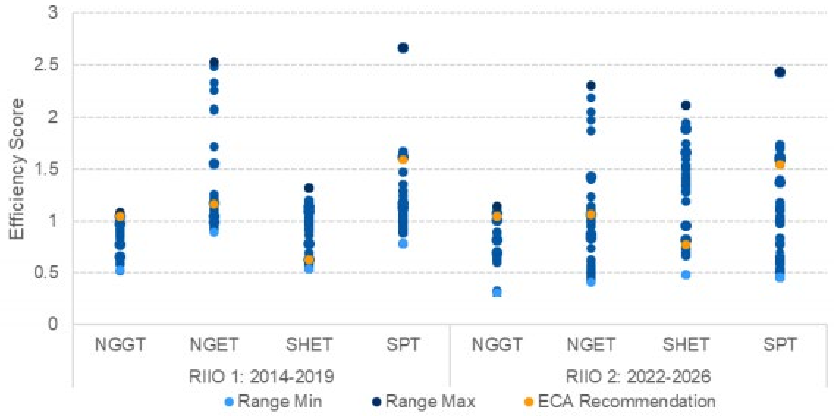
- Different ways of treating scale economies;
- Alternative cost drivers and combinations of cost drivers;
- And alternative model forms.

Figure NGGT48 - Efficiency scores for CAI across a range of models that meet ECA’s own model selection criteria



Source: NERA analysis. Note: We illustrate the efficiency score for NGGT implied by ECA’s modelled and prior to Ofgem’s adjustment.

Figure NGGT49 - Efficiency scores for BSC across a range of models that meet ECA's own model selection criteria



Source: NERA analysis.

For both CAI and BSC models NERA found a number of alternative models that met phase I model selection criteria but varied widely in forecast efficient costs. Specifically, for NGGT, CAI efficiency scores could be between 0.72 and 1.49, and BSC efficiency scores between 0.31 and 1.14. Whilst the alternative models also suffer from the limitations we have highlighted above, they all meet Ofgem's stated statistical criteria for a preferred model and, under the approach taken by Ofgem for Draft Determinations, could all equally have been used to set indirect cost allowances for RIIO-2. NERA conclude that "Ofgem's decision to rely on a single model masks this uncertainty" and that there is "a wide range of uncertainty around the degree to which individual TO's "efficient costs" vary from their business plan forecasts.

Our RIIO-2 submission for CAI and BSC costs fall within the efficient range of Ofgem's preferred models

We looked in further detail at ECA's preferred models and plotted our business plan costs against the range of efficient spend predicted by the model, as indicated by the model coefficient confidence intervals. As the chart shows, our submitted business plan costs fall well within the confidence intervals of the model and represent a more credible trajectory from RIIO-1 costs than Ofgem's modelled costs, given the ongoing nature of activities they fund.

Figure NGGT50 – CAI RIIO-1 and RIIO-2 forecast costs and Ofgem modelled CAI costs and confidence interval

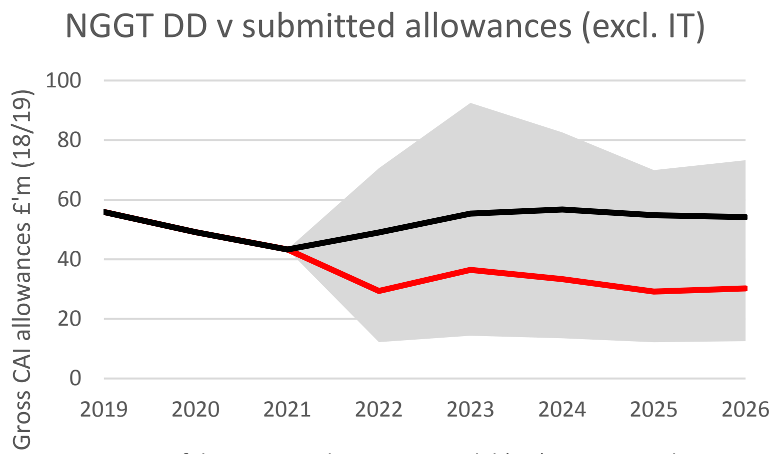
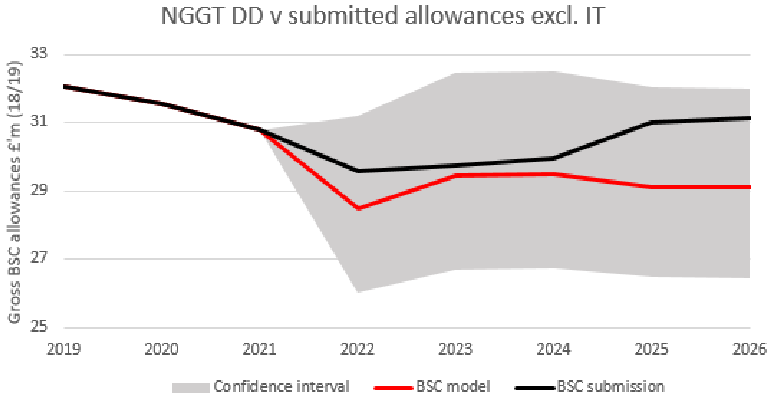


Figure NGGT51 – BSC RIIO-1 and RIIO-2 forecast costs and Ofgem modelled CAI costs and confidence interval



Our analysis demonstrates that Ofgem's preferred models cannot be used to reject our business plan as being inefficient. Considered alongside the evidence of activities that are supported by CAI costs and upper quartile external benchmarking evidence supporting our BSC costs, as well as the justification we have provided for the limited upward cost pressures we foresee in RIIO-T2 Ofgem should accept our proposed CAI and BSC costs in full in their Final Determination.

Earlier consultation on the approach for assessing indirect costs would have enabled a better outcome in the Draft Determinations

Ofgem's use of regression analysis as the sole tool for assessing Transmission network indirect (CAI and BSC) costs represents a new cost assessment approach to those used in previous price controls. Prior to their Draft Determinations Ofgem had not given any indication of considering regression type analysis for Transmission, in fact all the indications were that Ofgem would follow a process that was adapted from RIIO-ET1. For example, in their May 2019 Sector Specific Methodology Decision Ofgem confirmed their intent, first raised in December 2018, to "adapt the RIIO-ET1 cost assessment process, as appropriate, rather than establish a new approach for RIIO-ET2".

Nor did Ofgem consult on this approach as part of the RIIO-2 tools for cost assessment consultation in August 2019. Whilst econometric approaches were part of this consultation they were described as the "primary cost assessment tool for gas distribution networks"; only "assessment of business support costs, ongoing efficiency and RPEs" were consulted on for all sectors. Ofgem further distinguished Transmission cost assessment approaches from the topics being consulted on by going on to state, "Further detail on other cost assessment tools that we more typically apply in the transmission sector are also provided (but for which we do not seek explicit views)".

Accordingly, NGGT and NGET submitted a joint response to the consultation, responding to questions relating to business support costs, ongoing efficiency and RPE's in line with Ofgem's guidance that these areas were relevant to the Transmission sector. Ofgem have not published a decision to date and the status of this consultation remains "Closed, awaiting decision".

Had Ofgem consulted networks and other stakeholders on their intention to adopt this cost assessment approach for Transmission indirect costs for the first time in advance of Draft Determination we could have raised earlier the issues of methodology and principle that we have highlighted above, allowing time for proper consideration and reflection within Ofgem's Draft Determination cost assessment process. We expect that Ofgem will carry out thorough consideration of its model prior to Final Determinations, including considering the views gathered through the Draft Determination process and carry out further engagement with stakeholders as appropriate.

Ofgem did not seek evidence from NGGT as to the efficiency of its indirect costs
Following the submission of our business plan in December 2019 we were required by Ofgem to respond to any questions they had on our plan through the "subsequent questions" process. We received a total of 9 questions on CAI costs through this period, largely relating to understanding trends in costs over time and understanding how we had sub-categorised CAI costs. The final question was responded to on 11th May. We were not asked by Ofgem to provide explanation or evidence for our comparative performance in a regression analysis with Electricity Transmission networks, contrary to the advice ECA gave to Ofgem to do so.

We contacted Ofgem on 30th March 2020 to offer the opportunity to discuss our indirect cost plan with Ofgem in more detail and to understand Ofgem's forward plan for assessing opex, however it was not just prior to the publication of Ofgem's Draft Determination, that we learnt that Ofgem had used a econometric approach to assessing Transmission costs. ECA's econometric models were made available to us on 16th July, the week following publication of the consultation on 9th July.

Ofgem have committed to ongoing bilateral engagement in respect of their assessment of indirect costs for Final Determinations and we welcome the opportunity to discuss the points we have raised here, including our view of the remedies needed for Final Determinations.

IT & telecoms operating costs
We do not agree with Ofgem's decision to disallow our IT & telecoms in line with Atkins' assessment. The rationale for disallowing costs was unclear from Atkins' report and inconsistent with its treatment of NGET IT & telecoms costs, a proportion of which relate to applications and infrastructure that is shared with NGGT. Our IT operational costs reflect the costs of supporting our IT systems and we submitted evidence of the efficiency of our costs going into RIIO-2 in the form of a comprehensive benchmarking review performed by independent experts Gartner. We embedded our ambitious ongoing efficiency commitment of 1.1% per annum into our IT operating costs which more than offset the incremental costs of new investments we proposed in RIIO-2.

Ofgem has proposed that the ESO 'implement a new autonomous IT model from the beginning of the 2023-25 Business Plan'. NGGT shares the cost of a number of applications and general infrastructure also used by ESO and our December business plan was based on the assumption of a continued arrangement. Any cost implications of the move to an independent model will therefore require future consideration, either through the re-opener at the start of T2 or an alternative appropriate mechanism to be identified.

Quarry & Loss
We broadly support Ofgem's proposal to provide baseline funding for the predictable elements of quarry and loss and subject the unpredictable elements (Loss of Development and Sterilised minerals costs) to a reopener.

However, in terms of the reopener we believe that costs should be assessed as part of close out in addition to the year 2 reopener. Quarry and loss costs are incurred throughout the price control and we are legally obligated to address these (see response Q36).

However, we believe there is a real risk of cost increase in loss of crop, and we therefore believe it is appropriate to include these in the quarry and loss costs assessment at closeout (see response Q36).

The risk of cost increase in loss of crop arises from the following:

- Potential increase from new grantors requesting compensation
- Claims due to landowner compensation as a result of reduced depth of cover issues where we put a restriction on land usage for a period of time to protect the pipeline from damage. When we find reduced depth of cover in some cases we instruct the land owner not to use heavy machinery in that area or fence the area off to prevent farming. In these cases the land owner

is entitled to compensation due to loss of crop. We are finding more of these issues particularly in East area so there is certainly a risk that costs increase.

NGGTQ32. Do you agree with our proposed approach to Pensions costs?

Table NGGT52 - pension costs

Category	Submission (£m)	DD (£m)	Response (£m)
Pre adjustments	19.31	18.72	19.31
Efficiency	-0.60	-0.33	-0.60
Total	**18.72**	**18.39**	**18.72**

We agree with Ofgem's decision to fund pension admin and PPF levy costs in full and encourage Ofgem to retain this decision in their Final Determination. These costs were previously treated as outside of totex due to our negligible ability to influence these costs.

The pension costs forecast in our Business Plan are efficiently incurred and largely unavoidable. Networks have limited control over them. PPF Levy costs are set autonomously by the Pensions Regulator and we have limited control to influence it. We have a demonstrable track record of effectively minimising costs as far as possible.

We have previously shown in our triennial Reasonableness Reviews that our scheme administration costs are low, relative to other similarly sized pension schemes, and our scheme governance and processes are designed to consider the consumer-impact of decisions, and to champion the interests of energy consumers.

Given the nature of these costs, and our track record of efficiency and consumer-focus in managing them wherever possible, they should be covered in full by the RIIO-2 Totex allowances.

In addition to the above, we repeat our previous support for Ofgem's approach to Past Service Established Deficit (PSED) pension costs. Although these costs are not specifically referred to in 3.465 of the NGGT Annex, and fall outside of Totex, they are included in our Business Plan. Ofgem have previously indicated that these PSED costs would also be left unaltered, until the triennial Pension Deficit Allocation Methodology (PDAM) review, which is currently underway, is completed in November 2020.

We agree with Ofgem's approach in this regard, and support Ofgem's decision to allow the PDAM review process to continue to run alongside (in parallel but separate from) the RIIO-2 consultation process. The outcome decision of Ofgem's 2016 Pension Deficit Funding consultation found that the PDAM process was robust and consumer-focused, and we see no benefit to changing an already well-established and efficient process.

Assessment of risk and contingency

NGGTQ33. Do you agree with our proposed approach to assessing risk?

We are in general agreement with Ofgem's summary of its proposed approach to assessing risk. It would have been helpful for Ofgem's expectations to have been communicated earlier at the SSMD stage or in business plan guidance. Nevertheless, we note that the practices already adopted by NGGT for its RIIO-2 business plan submission are in line with the proposed principles.

Where we have comments on the application of the principles in specific areas of our plan, we have raised these within the relevant sections e.g. NGGT Cyber OT.

We suggest for consideration that one additional bullet be added to the list of principles in 3.470:

- Consideration of risk allowance will have regard to project maturity, delivery complexity, the availability of benchmarks, and the prevailing regulatory treatment which affects attribution of risk and reward between NGGT and consumers e.g. UIOLI / TIM.

3. Adjusting baseline allowances to uncertainty

Uncertainty mechanisms

Q34. Do you agree with our proposed UM for incremental capacity, specifically the timing and content of the Pre-Application Notification stage, the Needs Case and Cost Assessment timings, and the need for an exceptional events mechanism?

In the proposed UM for incremental capacity, we support the move from a generic approach to a case-by-case assessment, albeit with a defined process to establish the works included in the reopener and having regard for the variability of site-specific factors. We also support the decision to have no materiality threshold or specific window for the re-opener submission, given the variable nature of projects and their trigger from customer applications, plus the continued requirement to publish notices following such requests.

Although the re-opener does not intend to adversely affect timings of other processes or introduce delays, careful consideration must be given to the interaction with our capacity obligations, the PARCA framework and associated statutory planning activities. This is highlighted in the project submission comments below and in our response to the core document consultation question Q31 on the application of late competition to the incremental capacity process.

Pre-Application Notification

We understand the intention behind the pre-application notification and welcome steps to formalise our engagement with Ofgem and prepare for the project submission. However, we propose this step would benefit from being supplemented or replaced by an earlier need case assessment – see below.

Project submission

We note that the guidance document that could provide more information on the requirements and timescales of the re-opener is currently unavailable. We propose that any key step or requirement is included in the licence for clarity of our obligations and transparency for the customers requesting incremental capacity.

The proposed project submission combines both need case and cost assessment and occurs post planning consent. We understand the need for the final assessment to be undertaken post planning consent, however based on the timelines in the PARCA process and our current experience of incremental capacity projects, the available time between planning consent and the start of construction to meet capacity delivery dates for the customer are constrained. Agreed timeframes for assessment and consultations, plus deadline dates for determinations, are required to ensure efficient project planning and that contractual obligations are met. Without these and their alignment to the frameworks in place, there could be significant detrimental project impacts e.g. if delays caused a construction season to be missed.

We propose the introduction of an initial needs case assessment earlier in the re-opener design, as seen within the ET sector, potentially aligned with the production of the PARCA Phase 1 Output Report or the Phase 2 Strategic Option Report. Whilst it is understood projects may develop over time, this could provide time savings during the project submission, where the need case would be revisited but to a lesser degree. Equally, this would introduce a stage to establish the benefits to consumers, prior to incurring potentially significant costs associated with the planning process, project development and procurement activities. The level of detail for decision at this stage needs the right balance between the potential benefits of earlier assessment and the increased interaction and resource requirements.

Exceptional Events

We understand the principle behind the exceptional events mechanism but need more details in terms of what the certain events are and what materiality threshold applies. We will continue to work with Ofgem on the details of this mechanism through the licence drafting working group process.

NGGTQ35. Do you agree with our proposed UM, materiality threshold and trigger for pipeline diversion costs?

We agree with the decision to retain an UM for Pipeline Diversion costs. We understand the need for a fixed reopener window and materiality threshold to provide more certainty for both NGGT and Ofgem to prepare for application submissions. However, there may be circumstances where third-party requests for pipeline diversions do not occur until later in the price control period, or where they may fall below the materiality threshold. We therefore propose that an end of RIIO-2 period close out mechanism is required that shall allow for upward adjustment of allowances in respect of costs efficiently incurred irrespective of whether the reopener materiality thresholds have been reached or whether prior reopener applications have been made. This is to ensure NGGT is held whole for relevant costs legitimately incurred outside its control.

NGGTQ36. Do you agree with our decision to retain a UM for Quarry and Loss costs relating to loss of development and mineral sterilisation only, and do you agree with our proposed UM parameters?

We agree with the decision to retain an UM for Quarry and Loss costs relating to loss of development and sterilized minerals, as these areas of spend are largely unpredictable. We understand the need for a fixed reopener window and a materiality threshold for this within-period submission window.

However, there may be circumstances where we are not aware of these types of claims until later in the price control, or where they may fall below the materiality threshold. We therefore propose that an end of RIIO-2 period close out mechanism is required that shall allow for upward adjustment of allowances in respect of costs efficiently incurred irrespective of whether the reopener materiality thresholds have been reached or whether prior reopener applications have been made. We do not believe if these costs are addressed at close out that materiality thresholds should apply. Ofgem are proposing in their DDs no baseline allowance for these costs relating to loss of development and sterilized minerals, and NGGT should be held whole for these relevant costs legitimately incurred and "logged up" outside its control.

As a remedy Ofgem should include an end of period close out mechanism, with no materiality threshold for loss of development and sterilized minerals, to provide an allowance for RIIO-2 actual costs incurred not covered by the reopener.

Please also see within our response to question 31 views relating to loss of crop inclusion in close out arrangements.

NGGTQ37. Do you agree with our proposed asset health UM, specifically basing the UM on improved quality of cost data and volume measurement and assessing costs ex post?

We agree with the proposal of an asset health UM where this ensures that vital work to maintain the health of the network can be completed whilst protecting both consumers and National Grid from large variation in actual costs. However, there is no developed mechanisms to agree to at this time, we are and will continue to work with Ofgem to develop one in the best interests of consumers and stakeholders.

It is right that Ofgem accept the need to fund investment in our assets now to manage risk and condition that promotes a lower whole life cost of the asset. This is the optimum outcome for consumers. This is consistent with the proposal to provide three years of ex-ante funding that will be subject to ex-post review at the time of the proposed re-opener. It is also important for stakeholders and consumers that NARMs assets within the UM should have a minimum long term risk benefit agreed to be funded and that an efficient cost should be set to deliver that as a minimum.

We recognise Ofgem’s request for us to continue to develop cost reporting through the annual regulatory reporting process based on the system and process changes we will have in place for RIIO-

2 investments. Utilising this for regulatory purposes will help stem the growing cost and complexity of regulatory reporting and is beneficial to consumers. Finding the right, proportionate level of granularity and materiality for such enhanced reporting will set a very clear framework within which the UM will be able to proceed.

It is helpful that Ofgem have said that as soon as possible they will provide us any specific requirements around granularity or asset detail that they expect to see. We wish to ensure that the data we are capturing when delivering investments is agreed with Ofgem as soon as possible and a commitment to this being the basis that re-opener decisions will be made included in the Final Determination and potentially the transmission licence. This will give both NGGT and Ofgem certainty of requirements as we approach the re-opener ensuring a smooth assessment process that is ultimately in the best interest of consumers.

To not constrain this data driven approach we propose a flexible reopener window in year 2, 3 or 4 to allow NGGT and Ofgem to agree suitable evidence requirements for each asset theme and allow the setting of ex-ante allowances at the earliest opportunity in the price control.

Also outlined in NGGTQ25 we are also proposing that; Civils, Security and Fencing, Access and Buildings, Site Access Roads and Paths Major Refurb and Civils, Security and Fencing, Access and Buildings, Security - Fences and Gates - AGI (Minor Works) be subject to the asset health UM.

The re-opener should be developed further to more specifically reflect the specific asset concerned. As such we propose that the single stage Project assessment process[38] can be effectively used for certain asset health investment where high level of scope and cost certainty can be achieved at the early design and scoping stage. Cabs and civils investments are appropriate for this process. In engagement during the consultation period Ofgem indicated that utilising a project assessment approach for certain assets was sensible. We have provided annex – NGGT_Annex_AH UM proposals that outlines our initial proposal for the process of this uncertainty mechanism. We expect to continue developing the detail with Ofgem.

<u>Civils</u>

For the two UIDs we propose to include in the UM Ofgem's current proposed volumes allows us to only complete work currently planned in the first year of RIIO-2. As these investments have matured, we have an increasingly clear picture of the interventions required across our network compared to the December business plan submission.

The uncertainty around the specific civil interventions is only in volume. Ofgem made no adjustment to costs for the volumes it allowed in Draft Determinations. We propose that the civils element of the re-opener is on volume only maintaining the unit costs to simplify that element of the re-opener.

We note that whilst cost for allowed volumes were not challenged that Ofgem's confidence was in the granular costs that underpinned the aggregated site level costs required by the unit of measure of the relevant UIDs. We will therefore develop our survey material to capture the scope of required work at this level of granularity. We will also require these enhanced surveys to clearly capture why observed condition leads to a need to intervene.

To provide Ofgem with the required confidence to fund the Civils works through an UM we are proposing the following timeline of activity. This is based on asset health civils investments being delivered as part of an annual rolling programme with a 3 year lifecycle. Year 1 survey sites, year 2 conceptual design, year 3 deliver works.

[38] To be used for the Kings Lynn subsidence project

The sites we plan to intervene on are well known and forecasted ahead of time as we align this AGI work with associated feeder outages. These feeder outages are driven by the In-line Inspection (ILI) plan which inspects all pipelines on average every 10 years.

For the civils works we are proposing to be funded through this UM we have already surveyed and are going through conceptual design for the RIIO-2 year 1 works. We will complete most of the RIIO-2 year 2 surveys in this final year of RIIO-1 and will begin RIIO-2 year 3 surveys in RIIO-2 year 1. This is outlined in the table below.

Table NGGT53 – Civils UM Timeline

		19/20	20/21	21/22	22/23	23/24	24/25
Project Delivery Year	RIIO-2 Year 1	Survey	Conceptual Design	Deliver			
	RIIO-2 Year 2		Survey	Conceptual Design	Deliver		
	RIIO-2 Year 3			Survey	Conceptual Design	Deliver	
	RIIO-2 Year 4				Survey	Conceptual Design	Deliver
	RIIO-2 Year 5					Survey	Conceptual Design

As we approach the end of RIIO-2 year 1 we will have completed surveys for more than half of all RIIO-2 civil works. We will know the planned feeder outages and so the potential sites we can intervene on. Together this will be significantly improved data upon which to base detailed forecasts for RIIO-2 year 4 and 5.

On this basis we propose to submit the civils re-opener at the end of RIIO-2 year 1 in January 2022. Seeking funding for the investment we will deliver in year 2 onwards.

<u>Baseline funding</u>
We expect that to prepare for the re-opener window we will use part of the ex-ante baseline funding provided to ensure that any required investment in RIIO-2 is developed to the right stage in time for the re-opener. We will also always begin work on the highest priority sites and assets to ensure we effectively manage the risk of the network.

For such projects, pre-construction costs can be reasonably estimated. Ex-post efficiency reviews of these pre-construction activities will be intrusive, time consuming and add lengthy delays at a time when agility and flexibility is critical, and be resource intensive across network companies, Ofgem and our stakeholders. To be able to deliver at the pace required we require pre-construction works to be funded as ex-ante allowances. In line with our response to GTQ3 we therefore expect ex-ante funding for the early development stages of the cabs investments included in the UM.

In some circumstances, provision of ex-ante allowances is not appropriate. For example, where some work delivery is required to determine an efficient cost. The plant and equipment theme being such a case. Here, an allowance which could be subject to true-up is more appropriate.

Our current proposal for timing of re-opener submissions is captured below. We believe flexibility is required for plant & equipment to ensure enough data is available for a re-opener to be successful whilst allowing ex-ante allowances to be set at the earliest opportunity in the price control.

The re-opener year is captured but assumes that the submission window will be late January ahead of the regulatory year starting as reflected in Ofgem’s current licence drafting.

Table NGGT54 – Reopener Timeline

	RIIO-2 Year 1	RIIO-2 Year 2	RIIO-2 Year 3	RIIO-2 Year 4	RIIO-2 Year 5
Cabs – Project UM			Re-opener		
Plant & Equipment – Unit Cost UM		Re-opener?	Re-opener?	Re-opener?	
Civils – Project UM		Re-opener			

We do not support the concept of an open-ended period within which for Ofgem to arrive at its re-opener decisions. Our view is that there must be a clear deadline within which Ofgem must make reopener decisions otherwise this adversely impacts the efficiency of the reopener process, our planning and execution of work and contracting with the supply chain.

We would like to see Ofgem commit to decision making timescales for each type of reopener. We would be happy to work with Ofgem in developing such timescales.

Please see our separate response to core document Q12 where we set out our further views in relation to Ofgem's proposed common approach for reopeners.

NGGTQ38. Do you agree with our proposed GT Opex escalator adjustment mechanism?
We support the principle of setting an ex ante allowance for the incremental indirect costs associated with delivery of capital projects. We asked for indirect costs of, on average 9.8% of the direct costs of capital projects, within our business plan (within the CAI category) which compare favourably to industry benchmarks. Agreeing the costs of managing capital projects through an ex ante mechanism reduces the administrative burden for Ofgem and networks in preparing and assessing reopener submissions, is consistent with Ofgem's approach to set ex ante allowances for highly certain costs and incentivises networks to find more efficient ways to deliver capital programmes and share those benefit through the totex incentive mechanism.

However, we have two key concerns with the opex escalator as it is currently proposed, related to the issues that we raise in NGGTQ31. Firstly, Ofgem's approach to setting baseline allowances for our indirect activities, both incremental indirect costs associated with capital projects and the ongoing indirect costs to support our network, contains significant bias and error resulting in a 40% reduction to our allowances, even after adjusting for changes in capital workload. Any adjustment mechanism will be insufficient to compensate from this inadequately funded baseline.

Secondly, the 0.754% uplift to baseline CAI costs for each 1% increase in capex is based on Ofgem's preferred CAI regression model, a model which for reasons we set out in detail above is biased and incorrectly estimates efficient costs. In their technical report prepared for us and Scottish Power NERA identify a number of alternative regression models that pass the statistical tests that ECA and Ofgem set for selecting their preferred model, and in so doing demonstrate a range of coefficients that could equally plausible be considered to be efficient compensation for incremental activities.

Given the scale of use of uncertainty mechanisms in the RIIO-2 framework it is right that Ofgem adjust indirect costs as additional costs are allowed through the price control. We propose that Ofgem retain the opex escalator mechanism and calibrate it in line with networks' evidenced indirect costs in addition to remedying the issues with baseline indirect cost funding that we raise earlier in this response.

4. Innovation

NGGTQ39. Do you agree with the level of proposed NIA funding for NGGT? If not, please outline why.

We do not agree with the proposed level of NIA funding for NGGT. The approach that Ofgem has used to benchmark our RIIO-2 allowances against our RIIO-1 spend on innovation fails to recognise the future needs of the gas industry to progress towards net zero and fund transformative markets and our network to transport hydrogen. The work required to reach net zero is not BAU. Therefore to base the level of funding on RIIO-1 risks a significant shortfall in funding required to deliver the necessary innovation to facilitate net zero.

There is also an error in Ofgem's calculations for the proposed amount for NIA funding in RIIO-2. NGGT's RIIO-1 innovation allowance is an average of £5m per annum, not £4.5m as stated by Ofgem. This gives a total of £25m not the £20m stated over the five year period. Although we do not agree with Ofgem's approach, if the approach continues to be used for Final Determinations, this error needs to be corrected.

Our NIA funding mechanism request was for £30m which was based on our initial energy system transition strategy and forecast of innovation projects in summer 2019 and a reasonable review of the innovation spend growth year by year through RIIO-1. The £30m was on the assumption that non BAU innovations to support net zero would have other funding arrangements suitable to cover an extensive portfolio of hydrogen development projects on the gas transmission system over the next 5 years. Since putting the business plans together further development on the innovation portfolio has been done alongside the HPDG working group activities.

We now have a portfolio of 52 projects requiring approximately £129m of funds, to allow us to accelerate the transition to hydrogen and deliver Net Zero at pace. Approximately £60m are applicable to the Strategic Innovation Fund and we don't believe any meet the criteria of the Net Zero reopener mechanism. This leaves the only funding route for the remaining £69m being through the Network Innovation Allowance, where Ofgem have reduced our business plan request from £30m to £20m, which significantly falls short of the funding required to be hydrogen ready. **We therefore propose an increase to the Network Innovation Allowance to £75m to bridge the gap between Net Zero and Strategic Innovation Funding mechanisms.** For more details please see NGGT Annex Innovation.

The full scope of activities around working group outputs such as the HPDG roadmap and FutureGrid were not included in the business plan submission and at our business plan proposal and Ofgem's Draft Determination proposed NIA funding levels, some key activities in our plans would need to find alternative funding or be delayed to RIIO-3.

Examples of hydrogen projects possibly at risk include:

- 'Project Union' – Front end engineering works, which would allow the future connection of the industrial clusters and potential strategic hydrogen entry points to form a UK hydrogen backbone that would reduce hydrogen build costs, improve resilience and allow excess hydrogen to reach demand centres away from the cluster.
- Project Centrum' – Front end engineering works, to design a solution to deploy low carbon hydrogen at scale into the Midlands and East Anglia with both blue and green hydrogen production facilities creating future jobs in the Theddlethorpe and Bacton areas.
- RIIO-2 FutureGrid phases - Our FutureGrid RIIO-1 NIC bid will accelerate the transition of the gas transmission network to transport hydrogen and deliver the UK's Net Zero 2050 targets. This ambitious programme seeks to build a hydrogen test facility from decommissioned assets, building on existing H21 distribution facilities. This will allow for comprehensive testing to demonstrate the ability to transport 2%, 20% and 100% hydrogen blends within the National Transmission System (NTS). FutureGrid is a platform that enables further work vital to our customers and stakeholders to facilitate the transition of the network, planned to commence in RIIO-2. Phase 2 will test and trial various hydrogen deblending technologies and also trial

compression of hydrogen and the impacts on the network. Phase 3 focuses on opening the facility for third party testing, facilitating SMEs in developing, trialling and implementing hydrogen ready assets vital for our future decarbonised network, whilst also providing a platform for training and upskilling our hydrogen workforce. The FutureGrid online phase will take our learning from the offline test environment and take this onto the NTS to inject hydrogen into the network and transport it to an offtake as a live consumer trial.

The table below shows the average allowance over the eight-year period for RIIO-1 was £4.96m and in the last three years it was £5.019m. This is in contrast with the statement by Ofgem as part of the Draft Determination that stated on average NGGT's allowance was £4.5m per year. Therefore, the proposal for RIIO-2 of £20m against the requested £30.9m represents a significant drop in like-for-like NIA funding. This has since been confirmed with Ofgem in a separate conversation, agreeing that the benchmark should be against a £5m per annum innovation allowance.

Table NGGT55 - RIIO-1 NIA allowance

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Average	TOTAL
Allowance	**£4,385,000**	**£4,643,000**	**£4,809,000**	**£5,037,000**	**£5,802,000**	**£4,802,000**	**£4,865,000**	**£5,392,000**	**£4,966,875**	**£39,735,000**
3 year moving avg	-	-	*£4,612,333*	*£4,829,667*	*£5,216,000*	*£5,213,667*	*£5,156,333*	*£5,019,667*		
% change YoY	-	*5.88%*	*3.58%*	*4.74%*	*15.19%*	*-17.24%*	*1.31%*	*10.83%*	*3.47%*	
RRP Spend	**£2,928,027**	**£3,817,581**	**£3,273,128**	**£3,875,077**	**£4,224,525**	**£4,668,611**	**£4,750,446**	**£5,300,000**	**£4,104,674**	**£32,837,395**
3 year moving avg	-	-	*£3,339,579*	*£3,655,262*	*£3,790,910*	*£4,256,071*	*£4,547,861*	*£4,906,352*		
% spend change YoY	-	*30.38%*	*-14.26%*	*18.39%*	*9.02%*	*10.51%*	*1.75%*	*11.57%*	*9.62%*	
% Utilised	**66.77%**	**82.22%**	**68.06%**	**76.93%**	**72.81%**	**97.22%**	**97.65%**	**98.29%**	**82.50%**	
3 year moving avg	-	-	*72.35%*	*75.74%*	*72.60%*	*82.32%*	*89.23%*	*97.72%*		

As demonstrated in the figure above, NGGT has carefully utilised our NIA allowance, targeting projects that deliver value and not just full spend of the allowance. As time has progressed, we've developed a matured pipeline of ideas which has generated potential NIA projects greater than the value of funding, resulting in near full utilisation of the allowance. This is representative of the acceleration of work in the whole energy system sector, requiring ever increasing speed and agility to tackle many challenges faced to provide a decarbonised energy system and help the UK achieve its Net Zero targets.

Our RIIO-2 funding request is supported by much greater levels of business as usual funded innovation and wider reach across alternative funding mechanisms and partnership models, for example such as the in-kind contribution of £1.8m of Hydrogen research into the HyNTS FutureGrid Phase 1 2020 NIC bid.

We welcome the ongoing discussions to help assess project criteria for NIA with Ofgem through the RIIO-2 innovation working group.

We do however, disagree with some elements of the assessment of our business plan against the NIA criteria as detailed below:

Undertaking other innovation as BAU - Does not satisfactorily meet the criterion
We disagree with the statement *'we were disappointed that the business was only willing to fund innovation for which risks are at a level that is acceptable to the business and/or is a guaranteed level of return to the customer that justifies the investment.'* We believe it would be imprudent to use any funds in a way that could make losses for our customers and business. Therefore, to safeguard

our consumers, we structure our prioritisation of activities around those that will provide the most benefits and are most likely to succeed.

The innovation activities are undertaken using different risk classification than other investments within the business which allows flexibility in prioritising benefits over risk. We can use suppliers (e.g. SMEs and start-ups) that would not, at present, meet the risk criteria for core investment work. This allows them to demonstrate capability which aids them in future bidding of investment work. Further to this, we have committed BAU funds to the NIC projects such as GRAID and FutureGrid to enable our future activities, although these activities are higher risk than that seen in our business activities today. Activities surrounding FutureGrid will include additional NIAs to support later phases and BAU activities around developing our asset strategies, subject to CAI opex funding.

We disagree with the statement *'we also share concerns of the RIIO-2 challenge group and NGGT's UG that innovation with in BAU activities was not embedded throughout the full plan.'* The BAU activities illustrated in our innovation strategy cover all three of our strategic themes and are key to ensuring the robustness of the NIA innovation activity and enable implementation in the future. In line with the Draft Determination NIA and NIC thematic requirements we have further aligned asset related innovation to BAU activities which we will make clear in future reporting systems.

BAU innovation is undertaken by our core operations and engineering teams providing value to our customers and is not included in the innovation funding reports. Some of these innovations are listed in our RRP annual reports and others are direct savings to investment projects. Our annual savings against targets can, in some cases, be aligned to innovative methods utilised for undertaking our activities. These also include many innovations implemented by contractors not recorded via NGGT methods. Moving forward to ensure visibility of these BAU innovations and others contributed by our contractors and suppliers, we will bring these teams together, celebrate the innovations, encourage and incentivise, record and support projects where possible to aid delivery.

NIA projects have provided a range of benefits for our business units including tools that can be utilised by the teams. In some cases, these tools are also then developed further by the business units to provide added benefit. An example of this is NIA_NGGT0099 NOMs (Network Output Measures) Analytics which produced a model that allowed the modelling of failure modes and produced plans for intervention. The Richmond project undertaken throughout RIIO-1 has led to numerous innovative business process and activities to ensure our actions remain competitive.

Application for best practices - Satisfactorily meets the criterion
Evidence of the sharing of best practices across National Grid Group to help embed a culture of innovation, has been further enhanced by the engagement of innovation within our key business processes; strategy, investment and standards. This is enabling us to ensure innovation and processes associated are recognized by a wider community across our business.

Processes in place to rollout proven innovation and the evidence that this is already happening - Does not satisfactorily meet the criterion
We disagree with the statement regarding our rollout activities. We have clearly demonstrated our end-to-end process from initial project development through to rollout. Our processes and systems enable us to identify opportunities for implementation early in the project and facilitate rollout. Through the RIIO-1 period we have developed our process robustness and systems to ensure we deliver robust results, and this can be seen in our outputs and spend profile.

We use the ND500 process for our investment programmes, with innovation a key deliverable in the T1-T4 gateways of the process. Innovation experts also sit on the programme board to ensure that during the early discussions for investments, any relevant innovation projects are identified. If gaps are identified, problem statements are formulated to enable the innovation teams to develop solutions aligned to future investments.

We have identified the need for a project process that enables the projects to deliver the standards and policies required to ensure innovation is ready for implementation and can be rolled out successfully. The process uses Design for Six Sigma (DFSS) methodology alongside business process to ensure robust innovation project results. The stages of the innovation projects run from ideation investigation through to innovation implemented and have key checkpoints with the project stakeholders throughout.

As outlined in our RIIO-2 Innovation Strategy (A17.03) submitted as part of our RIIO-2 Business Plan in December 2019, we have successfully rolled out several key NIA projects to date that have delivered £9.2m benefit based on an initial £2.1m spend, representing a 4:1 return on investment. There is no one-size-fits-all method for value tracking, so our approach has focused on developing a robust methodology that allows the flexibility to capture a range of benefits, both tangible and intangible, whilst ensuring the data is accurate and verified. We have developed a set of processes and controls that enable us to identify potential benefits and subsequently test the values we associate to these, ensuring figures accurately represent the value achieved. This is compared with the expected value set out within the Project Eligibility Assessment (PEA) at initiation.

Where projects have been implemented, they are categorised in three ways:

- Implementation Complete – Fully implemented and no further value is expected (one-off cost or benefit).
- Annually Accruing – Each year we expect a recurring value achieved. A validation exercise is undertaken to confirm the additional benefit has been achieved.
- Per Use – There have been specific applications that have been quantified and recorded, but further applications would require specific analysis.

Each project that has been implemented has a case study completed, which is backed up by the source data, a checks and balances checklist and a 'Data Point Definition', which details the rationale and calculations used for all figures within the case study. This approach was developed as a result of the work with PwC to produce the initial Innovation Value Report published in 2017 and ensures transparency in our value tracking process.

The nature of the innovation projects in NGGT tends to be on a larger scale, with projects that seek to address issues and opportunities that occur on large capital projects. Therefore, these applications may have many months or years in between use due to the timelines involved in such significant projects. This longer timeline may result in a lag in reporting an innovation project as "rolled out" as it is only quantified once used and implemented in a project. There are currently several innovation projects that are planned for rollout, but as they are part of large capital schemes, they will not be reported until the scheme has been completed.

As the figure below shows, applications of our NIA projects to date have had significant value delivered from a range of scenarios including cost avoidance/savings, value delivered to our customers through reduced cost or time and efficiencies brought through process improvements.

Table NGGT56 - RIIO-1 NIA project benefits

Implementation Complete		
Project Title	**PEA Cost**	**Benefits Realised**
Vent Stack Design	[redacted]	£84,000
Hot Tap Buried Sample Probe	[redacted]	£1,300,000
CP for Pipelines in a Tunnel	[redacted]	Safety & new policy (CCP/9)
Total	**£822,000**	**£1,380,000**
Annual Accruing Benefits		
Project Title	**PEA Cost**	**Benefits Realised**
Safety in PIG Trap Seals	[redacted]	£50,000
A Greener Generation of Air Compressors	[redacted]	£651,000
Total	**£217,000**	**£701,000**
Per Use Benefits		
Project Title	**PEA Cost**	**Benefits Realised**
Impact Protection Slabs	[redacted]	£767,000
Customer Ramp Rate	[redacted]	£80,000
BIM at Feeder 9	[redacted]	£885,000
BIM at Bacton & BIM at Peterborough and Huntingdon	[redacted]	£3,700,000
Improving CP Data with MiniLog	[redacted]	£144,000
Portable Valve Actuation	[redacted]	£680,000
Mini-Grouted Tee	[redacted]	£817,000
Total	**£1,040,000**	**£7,000,000**

Several projects in our RIIO-1 portfolio have been at lower TRLs than would make them implementable at the end of the project and these projects are followed on by projects that then enable delivery. Where the TRL is lower it is likely that these will not be seen in BAU activities for several years, therefore, we are only just starting to see some of the benefits identified in projects from the start of the RIIO-1 period. This can be seen in our annual summary 19/20 TRL level graphics.

The benefits described above are a selection of projects, an analysis on the full portfolio is underway to determine our performance through RIIO-1. It should be noted that not every project provides direct benefits and may provide benefits through knowledge, lessons, capability and other non-tangible benefits. Reporting of the benefits through the framework will ensure that we can demonstrate benefits through RIIO-2. We are supportive of the use of this tool and have already begun to use it with our RIIO-1 projects to ensure usability through RIIO-2.

Processes in place to monitor, report and track innovation spending and the evidence that this is already happening - Does not satisfactorily meet the criterion

We disagree with the statement regarding our processes to monitor and track innovation, as seen in the previous section we have processes in place to ensure delivery and as seen below a robust project management tool to enable the tracking and escalation of innovation actions. The National Grid Gas Transmission Innovation group utilise a project management tool called DFN that enables the tracking of spending, benefits and other key project management topics (risks/timing etc). The system allows live reporting of the data and escalation of key issues. The GTIGG (Gas Transmission Innovation Governance Group) utilises live data from the system to sanction spending and projects on a monthly basis and the Gas Transmission Innovation Project Review (GTIPR) utilise the live dashboards to manage progress and spend against each project. We have engaged in the Benefits Framework and have built the structure into the DFN system to allow data to be more easily disseminated.