Draft Determination

Redacted

NGET Draft Determination Response to NGETannex

As a part of the NGET Draft Determination Response

Introduction

Whilst we share Ofgem's objectives for RIIO2, the Draft Determination (DD) for NGET as it stands is unacceptable because it fails to meet the needs of current and future consumers as well as the needs of our direct customers and broader stakeholder base. This is because the package as a whole reduces network reliability and resilience, jeopardises the pace of delivery of a net zero energy system, and erodes regulatory stability and investor confidence in the sector.

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 new evidence. We note that on a number of topics Ofgem has specifically acknowledged that it is open to better options being brought forward, and potential weaknesses in current proposals. This is positive and important because we consider that a significant number of proposals are currently unacceptable and remedies are necessary for Final Determination to address serious issues identified.

We will continue to engage constructively with Ofgem and all stakeholders over the coming weeks to provide robust evidence and rationale to motivate and secure the necessary changes for Final Determination.

Navigating our response

There are eight parts to our overall response in which we provide the substantial evidence to justify and support the changes needed:

1. A short covering letter for GEMA
2. An executive summary of our response
3. A summary of key issues and proposed remedies
4. Our response to Ofgem's core DD document questions
5. Our response to Ofgem's Electricity Transmission sector document questions
6. **Our response to Ofgem's NGET-specific document questions**
7. Our response to Ofgem's Network Asset Risk Metric (NARM) document questions
8. Our response to Ofgem's Finance document questions

This document is part 6 of our overall response and provides a summary, in one place, of the major proposals across the suite of Ofgem's DD consultation documentation that are currently unacceptable to us with significant remedies necessary.

<u>Consultation questions</u>

NGETQ1 Do you agree that an Environmental Scorecard ODI-F would be in the interests of existing and future consumers?

We strongly agree with Ofgem that the environmental scorecard ODI-F will be in the interests of existing and future consumers because:

- ☐ It provides an incentive for NGET to deliver on our stretching commitments in our environmental action plan (EAP;
- ☐ It supports the regulator, Ofgem, in introducing the new EAPs to raise the profile of environmental issues and companies' environmental commitments in the RIIO framework, which will generate benefits for consumers; and
- ☐ The environmental scorecard ODI-F was supported by stakeholders at an NGET ODI webinar in October 2019 and an NGET environment webinar in November 2019.

NGETQ2 Do you support our proposed changes to NGET's Environmental Scorecard proposal?

Ofgem is proposing a number of changes to the NGET 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 DD, through its proposal on incentive rates in paragraph 2.17 of the NGET annex.

We prefer a scorecard ODI for the following reasons:

1. At the ET ODI webinar on 9 October 2019 external stakeholder preferred an environmental scorecard ODI to individual ODIs on the environment by 10 to 4 votes, with 6 people saying they had no strong preference. Therefore, Ofgem's proposal goes against the stakeholder feedback we received on this issue.

2. The environmental scorecard ODI provides one, relatively large, incentive rate to focus the minds of NGET and stakeholders on the importance of delivering the EAP. Seven mini-ODIs with smaller incentive rates might not provide the same focus.

3. 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 2.16, but it could preserve the scorecard nature of the ODI and adjust the overall incentive rate.

Second, Ofgem says that if it accepts the scorecard nature of the ODI it 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 2.14). 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 it continues with a scorecard approach.

Third, Ofgem proposes changing the metric "Percentage of our fleet that is alternative fuel vehicles" to one focussed on a direct measure of environmental performance (paragraph 2.15). We agree to make this change and to support Ofgem we proposed the information it needed to make the change to the metric "Percentage reduction in our fleet emissions" in May through an SQ response.

Fourth, 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 2.17). 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.

No.	Metric name	Proposed approach to the incentive rate
1	Percentage reduction in our 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 our business mileage	
3	Percentage of our operational and office waste	1. Use emissions factors to calculate greenhouse gases (GHG) emissions differences between landfill and recycling (source: DEFRA 2019 emissions factors kg/CO_2e). 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 for a reduction in water, including electricity used for treatment of water and wastewater.
6	Percentage increase in the environmental value of our non-operational land	We propose to base this incentive rate on our sector-leading natural capital tool and proposed Consumer Value Proposition (CVP) figures that we have been engaging with Ofgem on.
7	Percentage net gain on all construction projects	We have a meeting with SHE-T and Ofgem on 7 September 2020 to discuss aligning NGET and NGGT's ODI valuation methodologies with SHE-Ts CVP methodology. We will be able to provide a methodology for calculating the social value of net gain after these discussions.

We are keen to work constructively with Ofgem and NGGT, which has a similar ODI, to agree incentive rates by mid-October having done some further industry engagement on calculating whole-life total societal impact value.

NGETQ3 Do you agree with our proposal to reject the Accelerating Low Carbon Connections ODI-F?

We disagree with Ofgem's proposal to reject NGET's accelerating low-carbon connections ODI-F.

Our proposed ODI has the following benefits:

- The accelerating low-carbon connections ODI will encourage **large reductions in greenhouse gas emissions for consumers and future consumers** more quickly than they would otherwise happen. Bringing forward a 1GW wind farm connection by one year saves £50m of carbon emissions. Even under the conservative common energy scenario we're expecting to connect around 10GW of low-carbon technologies to our network in the RIIO-2 period, showing the potential value that we could unlock for consumers and future consumers could be up to £500m of savings in greenhouse gas emissions;
- The ODI will **enable low-carbon generators to connect to our network more quickly and grow their businesses more quickly**. The impetus and funding the ODI will provide us with will enable us to improve our connection processes to benefit all connecting customers.
- **The ODI has stakeholder support**:
  - We submitted a paper to Ofgem on 22 May 2020 following engagement with 8 stakeholders and those stakeholders were supportive of the aim of the ODI. (We have attached the paper as annex NGET_NGETAnnex_Q3a_ update on an ODI on accelerating low-carbon connections to our response.)
  - We have spoken to two additional stakeholders since our 22 May 2020 paper who are also supportive of the aim of the ODI.
  - The IUG encouraged us to develop the ODI and supports it: "The User Group, therefore, welcomes the action now taken by NGET to have the financial ODI [on connection lead times] in place from the start of RIIO-2." IUG report for NGET , page 21.
  - The RIIO-2 challenge group asked us to explain "what level of stakeholder support there is for this specific initiative, rewarded in the way and at the level proposed" RIIO-2 challenge group report, page 104. We followed up on this feedback from the RIIO-2 challenge group with specific discussions on the ODI with 10 stakeholders.
- There is **a profound change happening with low-carbon connections** in the next few years with more, smaller connecting low-carbon generators and battery providers wanting to connect to our network who want shorter lead times than we can deliver without taking on more risk in a low-return, high-risk RIIO-2 framework.
- **This ODI directly responds to Ofgem call** for network companies to propose "additional contribution to low carbon transition" ODIs as set out in Ofgem's sector-specific methodology decision (pages 62-65) and it responds to Ofgem's Decarbonisation Action Plan published in February 2020.

Ofgem provides four reasons why it has rejected the accelerating low-carbon connections ODI-F on page 18 of its DD NGET annex. Ofgem also added two additional *reasons for rejecting this ODI in an Ofgem-NGET bilateral video call on 7 August 2020. We address all six rationales for rejecting the ODI below.*

Ofgem rationale 1: We think that it would be difficult to set a meaningful and challenging baseline for this incentive, due to the lack of relevant historical or independently verifiable evidence. (paragraph 2.23). NGET explained that there is no relevant RIIO-ET1 performance data due to the lack of any customer request for acceleration of connection. (paragraph 2.20)

We recognise Ofgem’s concern about how to set a robust baseline for this ODI, which some of our stakeholders raised too. However, we should not allow this issue from stopping us unlocking the huge benefits this ODI could provide in terms of reducing greenhouse gas emissions.

We want to reassure Ofgem and our stakeholder that although we have not accelerated low-carbon connections in the RIIO-1 period, this is because for the generation projects we have commissioned in the RIIO-1 period, developers have delayed rather than wanting to accelerate their generation projects. However, the energy sector is changing, and we are seeing many smaller, low-carbon developers, whose supply chains are speeding up, wanting to connect more quickly to our network. This is one of the main reasons for developing the accelerating low-carbon connections ODI to anticipate new demands from our customers and ways we can reduce carbon emissions further.

We propose several solutions for setting robust baselines for this ODI which could be used individually or in combination:

- ☐ We could restrict the ODI to connections where there are existing contracts in place now and there is no scope for us to lengthen the lead time in response to this incentive.
- ☐ We can release more information on how we have calculated our baseline lead time for a new connection so that it can be challenged by the customer and or an independent body, such as the ESO.
- ☐ We can present evidence on what activities we will carry out to shorten the lead time and explain why these go beyond existing standard practice.

Ofgem rationale 2: We also think that it would be challenging to differentiate the effect of a TO's genuine effort to accelerate connection from the effect of additional contingency built into the original date. We do not think that the ESO or the User Groups would have the tools to safeguard against the risk of additional contingency being built into these connection dates. (paragraph 2.24)

In our response to Ofgem rationale 1 above we propose several solutions for setting robust baselines for this ODI which could be used individually or in combination:

- ☐ We could restrict the ODI to connections where there are existing contracts in place now and there is no scope for us to lengthen the lead time in response to this incentive.
- ☐ We can release more information on how we have calculated our baseline lead time for a new connection so that it can be challenged by the customer and or an independent body, such as the ESO.
- ☐ We can present evidence on what activities we will carry out to shorten the lead time and explain why these go beyond existing standard practice.

These solutions will help address Ofgem's rationale 2 because they will avoid there being additional contingency built into the baseline connection lead time.

Bullet points 2 and 3 also provide additional information to an independent body, such as the ESO, to safeguard against the risk of additional contingency being built into these connection dates.

The solution in the first bullet point does not require an independent body to verify the connection lead times because they are already in existing contracts.

Ofgem rationale 3: A core activity of a TO's operations is meeting the general needs of its customers and delivering timely connection dates. On the basis of the information we have at this time, we do not consider it appropriate for a regulatory ODI to replace what should be better managed through individual commercial processes. (paragraph 2.25)

The accelerating low-carbon connections ODI-F is needed to encourage risk taking and new approaches to accelerate the connections, which we are less likely to pursue on a commercial basis under the low-return, high-risk RIIO-2 package. Small, new low-carbon generators cannot afford to take on the additional cost of accelerating connections. There are therefore benefits in terms of lower greenhouse gases that consumers and future consumers are missing out on that could be created by this ODI.

Ofgem rationale 4: In addition, we note that the Quality of Connections Incentive should drive TOs to manage the connections process to meet its customers' needs, which includes delivering connections earlier, where appropriate (paragraph 2.26)

The quality of connections survey ODI is not sufficiently targeted to encourage us to accelerate our low-carbon connections, which involves risk taking and new approaches by us that will need funding.

The incentive rate for the quality of connections survey does not reflect the value to consumers of the avoided greenhouse gas emissions and so will not drive sufficient investment in accelerating low-carbon connections to generate benefits for consumers and future consumers.

Ofgem rationale 5 *(added at a bilateral on 7 August 2020): NGET receives an ODI reward even if the consumer benefits don't materialise under its proposal.*

There is a risk with connections that the customer delays its connection date and the investment we put into accelerating the low-carbon connection does not generate greenhouse gas emission savings for consumers and future consumers.

Following Ofgem's feedback we can drop our proposal that we should receive the ODI payment for accelerating the low-carbon connection whether the greenhouse gas emission savings materialise or not. We propose that we would only receive the ODI payment for actual greenhouse gas emissions saved. This is the case even though we will have put the investment into accelerating the low-carbon connection and the absence of the greenhouse gas savings is due to the connection customer rather than us.

Ofgem rationale 6 *(added at a bilateral on 7 August 2020): NGET could have an incentive on setting a shorter lead time as well as delivering it.*

We can see the merit in Ofgem's idea for an ODI to set a shorter connection lead time as well as an ODI to deliver it. Unfortunately, due to Ofgem's requirements for bespoke ODIs in its 31 October 2019 business plan guidance (paragraphs 2.16 and 2.17) and the requirement to engage with stakeholders on ODIs we do not have time to develop an alternative ODI at this stage.

As well as the six issues Ofgem raises above we addressed 19 comments from our stakeholder engagement in our paper that we send to Ofgem on 22 May 2020. We also provided a worked example for a solar farm in that paper in addition to the example we provided for a large wind farm in our NGET business plan annex ET.06 on Output Delivery Incentives (ODIs) . This shows that we have developed our ODI fully and subjected it to a large amount of scrutiny from stakeholders.

We urge Ofgem to approve the accelerating Low Carbon Connections ODI-F in its FD based on our responses to its concerns with the ODI, the large potential benefits for consumers and the robust scrutiny this ODI has received from stakeholders.

NGETQ4 Do you agree with our consultation position to reject the 'RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs'?

This answer to question NGETQ4 also covers our answer to NGETQ10 on the closely related topic of NGET's SO:TO optimisation CVP.

We disagree with Ofgem's proposed rejection of the TOs-ESO joint paper "RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs", (see annex [X] for the paper). We also disagree with Ofgem's proposal to reject NGET's SO:TO optimisation CVP.

Summary of proposals

The TOs-ESO joint paper included 4 stages, which it summarised on page 10 and we have reproduced below. Stage 2 is similar to an ODI proposed by SPT in its business plan and stage 4 is similar to a CVP NGET proposed in its business plan. We summarise this in the table below.

Stage of TOs-ESO joint paper	Related proposals in companies' business plans
Stage 1 - Streamline the administrative process for STCP 11-4 to make it quicker and easier to complete.	Not applicable.
Stage 2 - Introduce a common ODI from year 1 of RIIO-T2 for TO's to identify and progress asset-based solutions using STCP 11-4.	SPT's financial ODI on Whole System ESO-TO constraint mitigation, to identify and agree high-value constraint cost mitigation solutions with the ESO.
Stage 3 - Report on the forecast constraint cost savings and solutions to demonstrate consumer benefits.	Not applicable.
Stage 4 - Trial an "on-demand service" with a defined budget which could be provided through the network innovation allowance (NIA) for TOs who wish to take this forward.	NGET CVP8 on SO:TO optimisation, which proposes to save consumers money by providing the ESO with flexible options to reduce whole-system costs.

There are large potential consumer benefits that need unlocking

In our business plan, a subsequent paper we sent to Ofgem on 24 February 2020 and in the TOs-ESO joint paper we explained the large consumer benefits from SO:TO optimisation that our proposals could unlock.

The main evidence in relation to consumer benefits is:

- Figure 2 of the TOs-ESO joint paper shows total constraint costs for the 12 months from April 2019 to March 2020 were £714m. This is around £27 per household, higher than Ofgem's proposed savings from its RIIO-2 draft determinations.

- Table 1 of the TOs-ESO joint paper presents evidence from the NGESO Operational Assessment Report (Nov 2019) showing that forecast GB constraint costs will increase to between £1.7bn to £3.7bn per year by 2026, which will have a large impact on consumers bills.
- Through analysis of published constraint costs we estimate we could reduce whole system costs by up to £188m each year for England and Wales based on 2018-19 data. This benefits of NGET's proposal are likely to be even higher in RIIO-2 given the speed at which the ESO forecasts constraint costs will increase. NGET submitted a detailed paper explaining its calculation to Ofgem on 24 February 2020 (see annex NGET_NGETAnnex_Q3b_TOs-ESO joint paper on reducing constraint costs).

Ofgem has not questioned the evidence about constraint costs in the TOs-ESO joint paper and therefore we presume accepts that the constraint costs borne by consumer are very high and forecast to at least double and maybe even increase fivefold by 2026.

At paragraph 2.90 of its DD NGET annex Ofgem questions NGET's estimate of up to £188m of annual savings (based on 2018-19 data) by saying:

> "however, we do not think that these estimates account for other opposing constraints. Therefore, we do not believe that they provide an accurate representation of potential consumer benefits."

Given the scale of potential consumer benefits from our proposal we asked Ofgem for an explanation of its concerns about our calculations in an email on 13 July 2020. Ofgem replied on 20 July stating:

> "…we will consider further whether there is any further direction we can provide in this area. We would expect to communicate this in the early stages of the consultation period, and can discuss further at the TO workshop next week, to the extent that should be useful and appropriate."

Ofgem never provided any further feedback on our consumer benefit calculation or its concerns about "opposing constraints".

We have been pursuing our SO:TO optimisation proposals with Ofgem, the other TOs, the ESO and other stakeholders for 2 years. Despite Ofgem rejecting our proposal and the TOs-ESO proposal at DD we will continue to push them because they are the right thing to do for consumers and could save them a considerable amount off their bills.

Delivering consumers benefits in a way that follows Ofgem's policy (incentives and competition)

As we discuss below Ofgem seems to prefer relying on a purely regulatory approach to the SO:TO interface in its DD. However, the TOs-ESO joint paper, NGET's CVP and SPT's ODI are based on incentives and competition-based approaches, which is in keeping with Ofgem's RIIO-2 policy:

- "We do this by setting Revenue using Incentives to deliver Innovation and Outputs." (Ofgem, RIIO-2 framework decision, executive summary, July 2019).

- "We proposed to extend competition across the sectors (electricity and gas, transmission and distribution), where it is appropriate and provides better value for consumers." (Ofgem, RIIO-2 framework decision, page 11, July 2019).

We explain below how our proposals for SO:TO optimisation follow Ofgem's RIIO-2 policy on incentive and competition.

Addressing Ofgem's concerns with our proposals

Ofgem raises a number of concerns with the TOs-ESO joint paper, NGET's CVP on SO:TO optimisation and SPT's ODI on whole-system ESO-TO constraint mitigation. We explain in this section how we can allay Ofgem's concerns so that we can take forward these proposals in RIIO-2 and unlock a large amount of benefit for consumers.

Stage 1 of the joint paper

We understand that Ofgem broadly accepts Stage 1 of the TOs-ESO joint paper about streamlining the administrative process for STCP 11-4 to make it quicker and easier to complete. This is because Ofgem says:

> "We encourage the TOs and the ESO to continue discussions on how to resolve the barriers that they have identified [with STCP11.4], and to utilise the existing STC modification process, where appropriate, in order to explore any possible changes to STCP 11.4 through the STCP panel process" (paragraph 2.29, DD NGET annex).

Stage 2 of the joint paper / SPT's ODI proposal

Ofgem rejects Stage 2 of the TOs-ESO joint paper, which is to introduce a common ODI from year 1 of RIIO-T2 for TO's to identify and progress asset-based solutions using STCP 11-4.

Ofgem's rationale 1 for rejecting stage 2 / SPT's ODI proposal
Ofgem's first rational for rejecting stage 2 is:

> "We have not seen sufficient evidence to support the need for an ODI to encourage the use of STCP 11.4 at this time. We note that this STCP was recently introduced and we do not think that there has been sufficient time to understand the impact that STCP 11.4 will have. We intend to monitor the use of STCP 11.4 through the KPIs that have been included in the NAP proposal put forward by the TOs for RIIO-2; KPI 11 in particular. These KPIs will enable us to better understand TO outage management and the use of tools such as STCPs over RIIO-2." (paragraph 2.30 of DD NGET annex)

Ofgem raises the same concern in paragraphs 2.16 to 2.18 of the DD SPT annex.

Ofgem has repeated to us its position that STCP 11-4 is a new mechanism that it needs time to assess whether it is working or not, for example Ofgem repeated this point at the Ofgem-TOs-ESO call on 13 August 2020 about SO:TO optimisation.

Our point in the joint paper and in NGET's business plan is that STCP 11-4 will not work even if you give it more time. In addition, there is not time to wait several years to see if STCP 11-4 will work when constraint costs are already high and forecast to increase between two and five times during the RIIO-2 period.

The issues with STCP 11-4, as set out in the TOs-ESO joint paper are:

- **Uncertainty over cost recovery -** TOs can only recover their direct costs for the innovative service and only when it is used by the ESO.

- **The process is slow and burdensome** – The current STCP defined process for outage change (including costing and delivery) involves at least 16 steps with 8 separate interactions between the ESO and TOs.

- **Cap on costs** - Under the current STCP 11-4 rules there is a baseline limit of £1.147m (09/10 prices) per year on funding for commercial operational services, limiting the scope for TOs to provide a range of flexible services to the SO.

None of these issues will be solved by waiting to see if STCP 11-4 works, when the three TOs and the ESO have already identified these design issues, which means it will not work.

The TOs-ESO stage 2 proposal of a common ODI helps overcome these issues by:
- Providing more certainty over what funding a TO will receive if the ESO selects its option and allowing for a return on the risk-taking involved in identifying innovative schemes to offer to the ESO.
- Providing an incentive to negotiate the slow and burdensome STCP processes, which under stage 1 of the joint paper we propose to improve.
- Links the ODI payments to a share (c10%) of the actual constraint costs avoided through the provision of their services, enabling the cap to be raised because there is a clear link between payments to TOs and benefits to consumers that are many times higher.

We propose a sharing factor of 90:10 for consumers and TOs in the ODI to make sure that consumers benefit significantly more from the incentive that TOs do when there is a reduction in constraint payments. The proposal in the ODI was based on the reduction in <u>forecast</u> constraint saving, which we understand is consistent with many other payments in the constraint market to generators and how decisions are made by ESO in setting up the system ahead of time.

However, based on Ofgem's feedback about not wanting TOs to benefit from forecast savings that don't materialise and the ESO's feedback about forecast constraints being harder to calculate we can change our proposal. We propose that the benefits shared by TOs in this ODI are based on <u>outturn</u> constraint savings which are easier for the ESO to calculate and makes sure TOs only benefit when savings are actually realised.

Ofgem's rationale 2 for rejecting stage 2 / SPT's ODI proposal

Ofgem second rational for rejecting Stage 2 of the TOs-ESO joint paper / SPT's ODI proposals is:

> "We note that there are multiple other existing tools in place to ensure efficient collaboration and engagement between the ESO and TOs for the benefit of consumers in relation to constraint costs. These tools include the TOs' Licence Obligation to have and act in line with the NAP, obligations set out in the Security and Quality of Standard (SQSS), the Grid Code and the STCPs. We also note that the ENS incentive incentivises the TOs to reduce

> risk of energy not supplied and thus in some cases indirectly encourages efficient outage management" (paragraph 2.19 DD SPT annex)

The large benefit of the ODI over the obligations in the NAP is that it will actively encourage TOs to look for new and innovative solutions that can enable the ESO to reduce constraint costs for consumers. An incentive seems more in keeping with Ofgem's RIIO price control, where RIIO stands for "setting Revenue using Incentives to deliver Innovation and Outputs" (Ofgem RIIO-2 Framework Decision, executive summary, July 2018) than relying purely on obligations.

Without an incentive in place, and in order to meet our already challenging draft determinations on unit costs and delivery as NGET we anticipate no future increase in the use of STCP 11-4. It has already been demonstrated that STCP11-4 and the mechanism around it is not working for consumers and extending this mechanism to NGET will not resolve its problems. Unfortunately, continuing to rely on STCP11-4 means that consumers will miss out on a significant opportunity to see constraint costs and ultimately bills reduced.

<u>Stage 3 of the joint paper</u>
We understand that Ofgem broadly accepts Stage 3 of the TOs-ESO joint paper about reporting on the forecast constraint cost savings and solutions to demonstrate consumer benefits. This is because Ofgem says:

> "We consider that stage 3, as outlined by the TOs, will be sufficiently supported through the NAP KPIs." (paragraph 2.31)

<u>Stage 4 of the joint paper / NGET's CVP proposal</u>
As Ofgem identified at the Ofgem-TOs-ESO meeting on 13 August 2020 stage 4 of the TOs-ESO joint paper and NGET's CVP proposal share similarities:

- ☐ NGET's CVP proposal is for TOs will be able to offer the ESO a flexible range of delivery services when we take network outages. For example, rescheduling or accelerating timescales for delivery, providing alternative contracting, maintenance and construction activities, and working practices which otherwise would not be available. The ESO would market test the suitability of these services against a range of alternative options and select the most economic one for solving the system's balancing and/or operability need. The opportunity for TOs to earn a market rate for the extra cost and risk of delivering these services would provide a strong incentive for them to discover whole-system solutions to reduce consumer costs. It will counter the incentive for a TO to minimise its own costs in isolation, not taking account of whole system costs.
- ☐ The joint paper stage 4 proposes two main changes from NGET's CVP: trialling this approach during the RIIO-2 period rather than rolling it out in full; and using NIA funding rather than the CVP.

Ofgem's rationale 1 for rejecting stage 4 / NGET's CVP proposal
The first reason Ofgem gives for rejecting the stage 4 proposal in the TOs-ESO joint paper is that:

> "In addition, in our Sector Specific Methodology Decision (SSMD), we decided that the NIA would primarily focus on energy system transition and addressing consumer vulnerability. We do not think that this proposal falls within the scope of NIA." (paragraph 2.32 DD NGET annex)

Ofgem should not reject the potentially huge consumer benefits of the stage 4 / NGET CVP proposal for SO:TO optimisation a technical reason based on the source of funding. Ofgem could provide baseline funding with a clawback to fund the TOs-ESO joint paper stage 4 proposal if it does not think it fits within the scope of the NIA. This is not a reason for rejecting the substance of the proposal.

Ofgem's rationale 2 for rejecting stage 4 / NGET's CVP proposal

Ofgem states:

> "we cannot see a clear and identifiable gap in the current arrangements that would require new incentives and funding" (paragraph 2.85)

As we discuss above, there is a definite gap in the current arrangement that requires a new incentive or market-based solution. The issues with STCP 11-4, as set out in the TOs-ESO joint paper are:

- ☐ **Uncertainty over cost recovery -** TOs can only recover their direct costs for the innovative service and only when it is used by the ESO.

- ☐ **The process is slow and burdensome** – The current STCP defined process for outage change (including costing and delivery) involves at least 16 steps with 8 separate interactions between the ESO and TOs.

- ☐ **Cap on costs** - Under the current STCP 11-4 rules there is a baseline limit of £1.147m (09/10 prices) per year on funding for commercial operational services, limiting the scope for TOs to provide a range of flexible services to the SO.

Stage 4 of the TO-ESO joint paper and NGET's CVP proposal avoid all these difficulties by adopting a market-based approach in keeping with Ofgem's proposal "to extend competition across the sectors (electricity and gas, transmission and distribution), where it is appropriate and provides better value for consumers." (Ofgem, RIIO-2 framework decision, page 11, July 2019).

Under a market-based approach the TOs will be able to offer the ESO a flexible range of delivery services. The ESO would market test the suitability of these services against a range of alternative options and select the most economic one for solving the system's balancing and/or operability need. The opportunity for TOs to earn a market rate for the extra cost and risk of delivering these services would provide a strong incentive for them to discover whole-system solutions to reduce consumer costs. It will counter the incentive for a TO to minimise its own costs in isolation, not taking account of whole-system costs.

Consumers can only benefit from the market-based approach because the ESO will select the most economic solution from the range available to it.

Ofgem's rationale 3 for rejecting stage 4 / NGET's CVP proposal

Ofgem states:

> "In relation to the 'Getting more out of the existing network' proposal specifically, we note that enhanced ratings services are already available to the ESO, where the TO could provide relief to constraints on the system." (paragraph 2.87)

Ofgem is right that NGET offers enhanced ratings to the ESO, in the form of short term, cyclic and on some circuits weather-dependant ratings. Stage 4 of the TO-ESO joint paper and NGET's CVP proposal will give TOs a much stronger incentive to invest to identify opportunities for enhanced ratings and to incur the costs of providing them to the ESO. If it reassures Ofgem, TOs could be required to explain why an offer of enhanced ratings to the ESO was beyond business as usual and explain what extra research, costs and risks it had incurred to provide the option to the ESO.

Ofgem's rationale 4 for rejecting stage 4 / NGET's CVP proposal

Ofgem states:

> "we do not think that we have the tools to measure the impact of these proposals. We note that it is challenging to calculate the counterfactual constraint costs after the adoption of a flexible solution." (paragraph 2.89)
>
> "NGET provided its estimate of how much constraint costs could be reduced through the implementation of this proposal, however, we do not think that these estimates account for other opposing constraints. Therefore, we do not believe that they provide an accurate representation of potential consumer benefits." (paragraph 2.90)

As we mentioned above, given the scale of potential consumer benefits from our proposal we asked Ofgem for an explanation of its concerns about our calculations in an email on 13 July 2020. Ofgem replied on 20 July stating:

> "...we will consider further whether there is any further direction we can provide in this area. We would expect to communicate this in the early stages of the consultation period, and can discuss further at the TO workshop next week, to the extent that should be useful and appropriate."

Ofgem never provided any further feedback on our consumer benefit calculation or its concerns about "opposing constraints".

Ofgem should not allow the lack of perfect measurement of constraint costs prevent it from approving Stage 4 of the TO-ESO joint paper / NGET's CVP proposal when they could deliver huge benefits for consumers. The proposal can still deliver benefits to consumers if it is based on forecast of constraint cost savings because you would expect the ESO to get these on average right, even if in some cases the flexible services deliver much-larger-than-expected benefits and in other cases they deliver negligible benefits. It is not credible to tell domestic consumers that we didn't try solutions for large and increased constraint costs because we can't measure them perfectly.

Ofgem's rationale 5 for rejecting stage 4 / NGET's CVP proposal

Ofgem states:

> "Lastly, we consider that this proposal could drive unintended consequences or inefficient behaviours through commercialising the ESO/TO relationship. There is a risk that this proposal could perversely incentivise the TOs to come forward with unjustified outage plans, which could create opportunities for the TOs to be funded to provide flexibility, which may not be in the interests of consumers. We are also concerned that this could encourage the TOs to prioritise certain works in order to retain CVP rewards." (paragraph 2.91)

We understand Ofgem's concerns about unjustified outage plans. We do not consider this is a realistic concern because the ESO challenges TOs strongly about their outage plans and we don't get all the outages we ask for now. We also ask Ofgem to consider the practical implications of TOs putting in place unjustified outages from which they only may benefit in the future set against the opportunity cost of getting access to other assets in the same area to achieve other regulatory and customer outcomes. We have a significant volume of work to do in our RIIO-2 plan and only through putting in place economic and efficient outage plans can this be achieved.

Nevertheless, a further solution to Ofgem's concern is that a TO has to present evidence to the ESO about why its offer of a flexible service is beyond business as usual and explain what extra research, costs and risks it had incurred to provide the option to the ESO.

Summary of NGET's position on reducing constraint costs and SO:TO optimisation

We disagree with Ofgem's proposed rejection of the TOs-ESO joint paper "RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs", (see annex [X] for the paper). We also disagree with Ofgem's proposal to reject NGET's SO:TO optimisation CVP.

Constraint costs are running at £714m each year and forecast to increase to £1.7bn to £3.7bn by 2026. The TOs and ESO have identified that the existing tools are not sufficient to address this large and increasing burden on consumers' bills and have proposed a number of solutions to Ofgem to address this. It is incumbent on Ofgem to take these proposals seriously given the potentially huge benefits to consumers they could generate.

In summary, Ofgem's three main concerns are:

1. There is no evidence of a gap in the existing tools to address high constraint costs;
2. It is difficult to measure the benefit to consumers from our proposal and consumers might not benefit if the proposal relate to forecast rather than actual constraint cost savings; and
3. The proposal might drive the wrong behaviours in the TO outage planning process.

NGET's response to Ofgem's three main concerns is:

1. In this response and in the TOs-ESO joint paper we have provided clear evidence that the current mechanisms are not working and explained that an incentive would provide the right signals for the TOs to take the risk of changing their well-justified outage plans and offer additional services to ESO.
2. Many constraint payments and system decisions are currently based on forecast information. However, to protect consumers further we could consider tying the benefits under our proposals to outturn constraint cost savings.
3. Our proposal would not drive the wrong behaviours in outage planning because of the impact on our own outage plans to deliver the work we need to carry out on the network, our regulatory commitments and the robustness of the current TO-ESO outage planning process. However, should Ofgem want to see further protections to address its concern we would be willing to implement them to enable the large benefit we see being realised for consumers from our proposals.

Ofgem should:

- ☐ Adopt the proposals in the TOs-ESO joint paper.
- ☐ In particular, Ofgem should implement the ODI under stage 2 of the joint paper with a conservative cap of £5m per year per TO that Ofgem can raise if the ESO finds that the ODI is generating large constraint cost savings.
- ☐ Furthermore, Ofgem should adjust stage 4 so that instead of using NIA funding Ofgem provides baseline funding to the TOs of £10m per TO to trial a market-based approach to providing flexible services to the ESO, which supports Ofgem's policy of promoting competition and can supplant the need for an ODI in the RIIO-3 period. Ofgem can clawback the baseline funding in the RIIO-2 close out process in proportion to any benefits not delivered to consumers.

NGETQ5 Do you agree with our proposals on the PCDs? If no, please outline why.

There are two sections to our response to NGETQ5 as follows:

- ☐ First, a response to Ofgem's proposed PCD framework because Ofgem has not asked a specific question on its PCD framework in its DD documents.
- ☐ Second, a response to Ofgem's proposals in Table 11 of the DD NGET Annex on 17 PCDs for NGET.

PCD framework

Ofgem has not included a specific question about its "PCD framework", which it covers in three paragraphs (4.8 to 4.10) of the core document. As question NGETQ5 refers to PCDs we are including our response on the PCD framework here. We look forward to working constructively with Ofgem on the PCD framework in the run up to final determinations.

We are structuring this part of our response as follows:

1. We support the principle of PCDs and they can benefit consumers.
2. Ofgem has not consulted properly on its PCD framework so far.
3. Ofgem has not explained why NGET has far more secondary deliverables than any other network company.
4. Ofgem's approach to PCDs, including secondary deliverables, which includes ex post reviews inhibits innovation and efficiency and is detrimental to consumers.
5. Ofgem has not been clear what the penalties are for not delivering PCDs and has not taken account of the potentially detrimental effects on consumers.
6. Ofgem has not been clear when the revenue changes resulting from Ofgem assessment of PCDs will take effect.
7. Ofgem must write the rules for PCDs into the licence rather than relying on guidance that Ofgem can change without protections for network companies.

PCD Framework Point 1 - We support the principle of PCDs and they can benefit consumers

We have always supported the principle of PCDs and that consumers and stakeholders should be able to see our progress in delivering them. We also support returning our allowance to consumers in proportion to any part of a PCD we have not delivered, unless we can show that we have delivered an equivalent output.

PCD Framework Point 2 - Ofgem has not consulted properly on its PCD framework so far

Ofgem has not made a proposal on the PCD framework in its draft determination meaning that network companies have not had a formal opportunity to be consulted on it. 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 DD, 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 shared a draft of its PCD policy paper on 28 August at the end of the seventh week of an eight-week consultation, which on a first reading appears not to address the issues we have identified below.

We will work constructively with Ofgem on the PCD framework in the run up to final determinations. However, Ofgem has not allowed network companies a full opportunity to comment on Ofgem's PCD framework as part of its DD because the PCD framework still requires large amounts of development after the DDs have been issued.

Remedy for PCD framework point 2: Ofgem needs to carry out a full public consultation on its PCD framework starting in September to provide adequate opportunity for stakeholders to respond to this fundamental part of the RIIO-2 framework.

PCD Framework Point 3 - Ofgem has not explained why NGET has far more secondary deliverables than any other network company.

Ofgem has introduced the concept of "secondary deliverables" in its DD and applied them disproportionately to NGET.

Ofgem had not mentioned secondary deliverables being part of the RIIO-2 framework until DDs. Secondary deliverables did not appear in any of Ofgem's consultations on RIIO-2 or in any workshops. Surprisingly, Ofgem did not mention secondary deliverables in the slides for its 18 August 2020 cross-sector PCD workshop, 6 weeks after introducing the concept for the first time in its DD or in its PCD policy paper on 28 August, seven weeks after the DD.

We asked Ofgem what secondary deliverables were in an email on 14 July 2020, but Ofgem was not able to provide a reply until 4 August 2020 taking three weeks out of an eight-week consultation period despite NGET raising the issue in three conversations with Ofgem.

Ofgem appears to be discriminating against NGET by requiring us to have 96% of the industry's secondary deliverables, with SHE-T being the only other company with secondary deliverables

Table: Primary and secondary deliverables by network company

	Primary deliverables	Secondary deliverables
NGET	54 (59%)	54 (96%)
SPT	34 (37%)	0
SHE-T	3 (3%)	2 (4%)
NGGT	0	0
Cadent	0	0
WWU	0	0
SGN	0	0
NGN	0	0
NGESO	0	0
Total	91	56

In its 4 August 2020 email Ofgem told NGET that:

> *"The number of primary v secondary deliverables is an artefact of the Business Plan submissions by the transmission companies' request for LRE and NLRE. We acknowledge that our presentation of the engineering requirements for PCDs may have raised questions. For different networks*

> *the engineering requirements may not have necessarily been captured within an EJP. For example NGGT received a confidential supplementary annex of engineering requirements for their PCDs rather than linked via an EJP. We will seek to provide a clarity on engineering requirements in our FP and at the PCD workshop*."

Ofgem's reply does not explain why NGET has 96% of the industry's secondary deliverables. For clarity, we did not mention secondary deliverables anywhere in our business plan.

As we explain in our response to point 4 below secondary deliverables, by requiring us to deliver the precise scheme in our Engineering Justification Papers (EJPs), stop network companies from delivering innovative or efficient solutions or from just taking account of changing circumstances. This will lead to worse outcomes for our customers and stakeholders.

> **Remedy for PCD framework point 3:** Ofgem should drop secondary deliverables for NGET to bring Ofgem's regulatory approach to PCDs for NGET in line with its approach for other network companies.

PCD Framework Point 4 - Ofgem's approach to PCDs, including but not limited to secondary deliverables, which includes ex post reviews, inhibits innovation and efficiency and is detrimental to consumers.

Ofgem's RIIO-2 sector-specific methodology decision (SSMD) states:

> "*We will ensure that the use of PCDs drives the right behaviours. We will build in*
> *sufficient flexibility to ensure genuine efficiencies are captured and acknowledged in assessing delivery against PCDs. We will ensure PCDs do not restrict network operators' freedom to innovate or be efficient in delivering the best outcomes for consumers. We believe this is a natural evolution for the RIIO framework that builds on the RIIO-1 approach, ensuring network operators retain the freedom to deliver for their consumers, while providing additional up-front clarity on conditions for funding*."

Ofgem's DD and its 18 August 2020 workshop slides back away from these principles.

Ofgem's DD requires us to deliver 54 secondary deliverables, which are the schemes set out in the EJPs. This allows us no scope to flex our delivery for something that is more efficient, innovative, fits changing circumstances or even adapts to a customer's changing requirements. Secondary deliverables are therefore clearly detrimental to our customers by pushing up costs, slowing delivery and reducing our flexibility to address our customers' needs.

Ofgem's 18 August 2020 workshop slides show Ofgem is applying the secondary deliverable approach to all PCDs. For example, principle 2 on slide 4 says that a network company can substitute an alternative solution for a specified PCD output, but if it does Ofgem will check that the alternative delivers an equivalent or better outcome and that any costs savings are attributable to genuine efficiencies or innovations, which the licensee will have to prove.

Slide 7 says "For the avoidance of doubt, changes in external factors such as, demand growth, government policy etc. will not be considered as genuine efficiencies. We will take into consideration the technical and economic (where applicable) needs case for the investment and expenditure being incurred, or any relevant obligations." These statements imply that Ofgem will remove the benefit of any external factors that go in a network company's favour when assessing its delivery of a PCD, but there appears to be no equivalent increase in allowances for when external factors go against a TO such as adverse weather, adverse demand conditions or adverse changes in government policy.

The effect of Ofgem's policy is to strongly discourage network companies from delivering anything other than their precise PCD outputs, even if it would be more efficient to do deliver alternative solutions. When considering an alternative solution, a network company will face much greater uncertainty over whether it will be able to recover its costs because Ofgem will require the company to prove any cost savings were genuine efficiencies or innovations, which Ofgem can take a different view on.

Remedy for PCD framework point 4: Ofgem should drop its ex post assessment of innovation and efficiency to avoid strongly discouraging network companies from taking innovative and efficient approaches to deliver for consumers. Ofgem should focus instead on network companies delivering their PCD outputs in the most efficient way for consumers.

<u>PCD Framework Point 5</u> - Ofgem has not been clear what the penalties are for not delivering PCDs and has not taken account of the potentially detrimental effects on consumers.

Ofgem has provided very little information on what the consequences are of not delivering PCDs. Ofgem must consult on these before FD. Following the consultation, Ofgem should incorporate the consequences for not delivering PCDs into company licences.

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

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

This proposal was not included in the DD or the Ofgem draft PCD policy paper on 28 August 2020. If this is formal Ofgem policy we are very concerned. 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 is affected by factors that a network company cannot control (e.g. constraint costs caused by late delivery can vary hugely depending on the weather and the conditions in the generation market).

At that workshop the TOs commented that Ofgem appeared to have ignored the year of work that TOs and Ofgem had carried out on the same issue under the Ofgem policy of large project delivery (LPD).

We wrote to Ofgem on 23 March 2020 (and SPT and SHET wrote to Ofgem in similar terms at the same time) explaining the potential detrimental consequences of disproportionate penalties for not fully delivering:

> "If you decide to apply additional penalties on TOs for delay, you need to take account of the possible perverse effects, which could be detrimental to consumers, of penalties for TOs which are too high. Requiring TOs to pay too high a level of consumer detriment penalties could:
>
> 1. discourage TOs from taking innovative approaches that are lower cost or deliver better service quality because they are new and subject to a greater risk of delay;
> 2. result in contractors increasing their prices to reflect TOs seeking liquidated damages in the event of delays;
> 3. encourage TOs to reduce risk and keep down insurance costs by using conservative delivery timescales;
> 4. increase the cost of capital as the sector is perceived by investors to have become riskier; and
> 5. encourage TOs to spend inefficiently to achieve a deadline with consumers picking up a share of these costs through the TIM sharing factor (especially if the TIM sharing factor for consumers is higher in the T2 period).

We explain our proposal for mitigating the impact of late delivery on page 56 of the NGET 200-page RIIO-2 business plan and pages 29-30 of our Annex NGET_ET.08_Outputs. Our proposal is that any contractual payments for damages we receive from suppliers should be the amount used to offset any consumer detriment from any delay or non-delivery. We propose that we would return these payments to our customers through lowering TNUoS by the amount of the consumer detriment payment. Our customers could then pass this reduction onto consumers. We are also incentivised to avoid delays by the additional costs that usually result from them."

Remedy for PCD framework point 5: Ofgem should take account of the potential issues that penalties for non-full delivery can have for consumers. Ofgem should formally consult on its approach to PCD penalties in September.

PCD Framework Point 6 - Ofgem has not been clear when the revenue changes resulting for Ofgem's 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: 1) making adjustments at T2 close out; or 2) with one or two mid-period reviews as well as T2 close out for PCD delivery. Ofgem needs to provide firmer proposals to network companies so that we can understand the risks to our financial profiles in the T2 period.

> **Remedy for PCD framework point 6:** Ofgem should consult in September on when the revenue changes resulting from Ofgem's assessment of PCDs will take effect.

PCD Framework Point 7 - Ofgem must write the rules for PCDs into the licence rather than relying on guidance that Ofgem can change without protections for network companies.

In paragraph 4.10 of the Ofgem DD core document, Ofgem says:

> "*We expect the links between specific PCD outputs and delivery modes used in our assessment to be clarified through the Licence and guidance documents.*"

We are concerned that in previous discussions Ofgem has raised the possibility of including important elements of the PCD framework in a guidance document (which it has not yet consulted on) that Ofgem can change with no safeguards for network companies rather than in the licence with appropriate 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 vital that the licence sets out clearly for each PCD:

- 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; and
- the process and timing of the recovery of any allowances for non, late and partial delivery.

> **Remedy for PCD framework point 7:** Ofgem should write the rules for PCDs into the licence rather than relying on guidance that Ofgem can change without protections for network companies.

Response on Ofgem's PCD proposals in Table 11 of the DD NGET annex

Please see below NGET's response below on your proposals on the 17 PCDs detailed in Table 11 – NGET bespoke PCD proposal (pages 21 to 24 of the DD NGET annex):

PCD 1 - Network reinforcements (Boundary capability)

We do not agree with having secondary deliverables as a PCD of this output category. We believe there will be no scope to flex our delivery for something that is more efficient, innovative, fits changing circumstances or even adapts to a customer's changing requirements. Secondary deliverables are therefore clearly detrimental to our customers and by pushing up costs and slowing delivery are detrimental to consumers.

The PCD value and primary outputs will need to be updated to reflect the 2019/20 NOA5 position. We do have concerns with how this will be managed throughout the price control as NOA's yearly publication will change the optimal path for many schemes.

PCD 2 - Maintaining security of supply as the energy system changes

The Draft Determination provides funding for the Protection & Control Coordination studies proposed, as confirmed in Table 17 'Additional LRE schemes' (NGET Annex p.48). Table 17 also states that, "When the study works are complete we propose to consider funding via the Medium Sized Investment Projects Uncertainty Mechanism rather than the separate mechanism NGET proposed". This is not currently reflected in the list of eligible 'externally-driven' investments, as indicated in our response to ETQ13. We would welcome an opportunity to work with Ofgem and agree the detail of a PCD for this investment.

PCD 3 - Facilitating the closure of conventional generation

The Draft Determination provides funding for site separation investment to facilitate the closure of conventional generation and highlights that a PCD could be a suitable approach to manage delivery. We would welcome the opportunity to work with Ofgem to further develop and agree a PCD which will provide greater certainty around output delivery and sufficient flexibility in delivery.

PCD 4 – Reducing carbon emissions from operational transport

We agree with the consultation position for this PCD.

PCD 5 – SF6 asset intervention

We agree with the consultation position for this PCD.

PCD 6 – Facilitating competition

We welcome the opportunity to work with Ofgem to set the defined outputs for this category ensuring the outputs are sufficiently flexible to accommodate different consenting regimes, will not impact the ability to seek alternative and innovative solutions that benefit consumers and accommodate the recommendations of NOA, e.g. where a scheme has a STOP signal.

The PCD value and primary outputs will need to be updated to reflect the 2019/20 NOA5 position.

PCD 7 – Optimising with the Distribution Network Operators (Reactors)

The Draft Determination provides funding for [redacted] reactor investments to manage high voltage issues in the north-west of England. We agree with the proposal for PCDs that are specific to reactor investments at identified sites. These baseline allowances need to be accompanied by a volume driver that automatically updates funding as requirements change and the PCD needs to reflect this. However, we do not agree with the proposed cost reduction as this would underfund the proposed reactor projects and not allow them to be delivered (see response to NGETQ11).

PCD 8 – Optimising with the ESO (System Monitoring)

The Draft Determination provides funding for the installation and operation of new system monitoring equipment to meet the requirements of STC-P 27-1. The DD indicates that a PCD might be a suitable approach to manage delivery. We suggest that a PCD defines a volume [redacted] of substations that will be upgraded to provide PMU capability by end of T2. This would also tie in with the STC-P 27-1 requirement to have coverage at all substations by the end of T2.

We welcome further engagement to develop this PCD in a way that protect consumers and provides sufficiently flexibility in delivery.

PCD 9 – Net-Zero capital carbon

We agree with the consultation position for this PCD.

PCD 10 – Black Start Capability

We believe we should be pro-actively investing in Black Start because it is in the consumer interest to provide the resilience levels that will be expected under a new standard. Within the National Infrastructure Commission report [Anticipate, React, Recover – Resilient infrastructure systems:https://www.nic.org.uk/wp-content/uploads/Anticipate-React-Recover-28-May-2020.pdf] it refers to the Regulator introducing obligations on Infra Co (by 2023) to develop and maintain a long-term resilience strategy and also requirements for stress testing. We were proposing enhancements to our Black Start capabilities to improve our ability in the 'Absorb'' element of the NIC framework - accepting there will be or has been an impact on infrastructure services, aim to lessen that impact.

However, we accept Ofgem's Draft Determinations acknowledging that the new standard has not been published by BEIS and therefore some uncertainty remains. We welcome this being included within the Medium Sized Investment projects (MSIP) re-opener mechanism. However there needs to be confirmation of regulatory allowances ahead of spend. This is particularly important because the challenging RIIO-2 finance framework proposed by Ofgem contains no contingency for networks to spend at risk or absorb small spends, therefore, we do not support there being a materiality threshold applied to this category or any other resilience categories.

These areas of expenditure stem from government mandated requirements to protect consumers and Ofgem should recognise this in the speed of its adjustment to regulatory allowances. As such we propose the regulatory treatment should be consistent with Ofgem's position of no materiality threshold being applied for Cyber Resilience. In addition, our proposed baseline investment for Black Start is £22m and therefore would not trigger the re-opener, whilst the re-opener window timing of January 2024 is too late in the price control period and should be earlier.

PCD 11 – Protection from extreme weather

Ofgem's Draft Determination position is unclear, the determination outlines that our request for Extreme Weather funding is rejected. Following engagement with Ofgem, it was confirmed that of the £59.8m requested, partial funding of £24.6m has been allowed as per the table below.

	NGET December 2019 Submission	Ofgem's Draft Determinations	Comments
Sites	£49.8m	£16.6m	30% of sites developed have been funded
Towers & Foundations	£8	£8	Fully funded
Research	£2m	£0	Not funded, research likely to have

			been completed elsewhere

We request that this be made clearer when the final decision is made for Final Determinations.

We do not agree with Ofgem's draft determination as we must implement the guidance in Energy Networks' Associations Engineering Technical Report 138 (ETR138) to protect our network against surface water flooding by the end of the RIIO-T2 period, as required by BEIS. Failure to invest in flood defences at the right level at the right time could result in devastating consequences for our customers and stakeholders, and the end consumer.

The intention of proposing the Extreme Weather investment as a Price Control Deliverable was that we would be held to account in the RIIO-T2 period to deliver [redacted] sites for £49.8m and therefore should detailed site assessments demonstrate that less than [redacted] sites need protection, the money would be returned, reducing the risk to consumers.

We are however submitting a revised proposal which needs to be funded at Final Determination, this is detailed in the table below with further evidence provided in NGET_NGET Annex_Q5_Extreme Weather. The revised spend profile can be found in Appendix 1 of that supporting document.

	NGET Dec 2019 BP Submission	Ofgem's Draft Determination	Final Determination proposal
Flooding	£49.8m	£16.6m	£47.2m
Erosion	£8m	£8m	£8m
Climate Change Research	£2m	£0m	£0m
Reopener	Yes – but only to cover further updates to ETR138	Yes – but only to cover further updates to ETR138	Yes – to cover *all* funding required to deliver ETR138
Total	£59.8m	£24.6m	£55.2m

Without the necessary funding Ofgem's Draft Determination leaves us with a funding gap to meet the current requirements of ETR138 and does not reference any regulatory mechanism to enable us to request the shortfall. If Ofgem is not minded to award the full funding, we propose that the scope of the MSIP re-opener should be extended to include all funding that may be required for Extreme Weather to meet the current and future requirements of ETR138.

Should Extreme Weather be included within the MSIP re-opener, there needs to be confirmation of regulatory allowances ahead of spend. This is particularly important because the challenging RIIO-2 finance framework proposed by Ofgem contains no contingency for networks to spend at risk or absorb small spends therefore, we do not support there being a materiality threshold applied to this category or any other resilience categories. These areas of expenditure stem from government mandated requirements to protect consumers and Ofgem should recognise this in the speed of its adjustment to regulatory allowances. The value is also unlikely to trigger the materiality threshold. As such we propose the regulatory treatment should be consistent with Ofgem’s position of no materiality threshold being applied for Cyber Resilience. The re-opener window timing of January 2024 is also too late in the price control period.

PCD 12 – A resilient operational telecommunication infrastructure

Operational Protection Measures and Operational IT capex (OpTel)

Our December Business Plan Submission identified a requirement for £186.9m capex investment for OpTel Refresh, with £108.9mm identified for Telecoms equipment replacement, implementation of a high bandwidth overlay and other enhancements and £78m to replace fibre-wrap which is approaching the end of its service life. Ofgem’s Draft Determination ‘does not fully accept the need case for OpTel refresh at present’ and does not differentiate between fibre-wrap and telecoms equipment refresh and proposes £62.1m allowance a ‘to enable works to begin’. This represents a reduction of 67% and will mean that obsolete telecoms equipment will remain in service presenting a significant risk to the reliability and resilience of the electricity transmission network.

The OpTel network is a highly resilient telecommunications network providing secure connectivity between substations and control rooms, and connects DNO’s, Generators and TO’s in Scotland. OpTel underpins critical tele-protection services and network monitoring and control (services and is essential to the safe, secure, reliable and economic operation of the electricity transmission network. OpTel is a designated Critical National Infrastructure (CNI) asset.

Loss or compromise of the OpTel network could lead to a loss of visibility, control and protection of our sites, resulting in a partial or complete loss of supply. In the event of a Black Start event OptTel provides the secure communication channels that enable us to effectively coordinate activities to restore electricity transmission when other communications networks are not available due to loss of electricity supplies.

The OpTel Telecoms equipment was installed between 2011-14 and some assets will be over 15 years old by the end of T2 when Telecoms operators typically replace after 10 years. We are extremely concerned that the consequence of reduced and/or delayed funding will mean that obsolete telecoms equipment remains in service into the T3 period with an unacceptably high risk of in-service failure and an increased cyber security risk to this CNI designated asset, which poses a serious risk to the reliability and resilience of the electricity transmission network.

Following submission of our Business Plan in December 2019 we have been working on our approach to OpTel telecoms equipment and fibre-wrap replacement. Recognising the different drivers for telecoms equipment refresh and fibre-wrap replacement we have split these into discrete projects and provided supplementary evidence to Ofgem in support of our plans. We believe that it is essential that the obsolete telecoms equipment is replaced as per our Business Plan Submission and have been working to develop a revised approach for fibre-wrap replacement using enhanced condition monitoring and an innovative approach to fibre-wrap deployment, which requires reduced investment and system access in the T2 period. This approach will enable ageing fibre-wrap to be prioritised and replaced over a seven-year programme at the lowest cost to the end consumer and with minimal system outage requirements, ensuring that the reliability and resilience of this essential service is maintained. The High Bandwidth Overlay (HBO) is required to meet growing demand for capacity due to additional services eg cyber security of operational technology (OT) and increasing data volumes eg asset condition data. The HBO is not constrained by the fibre-wrap replacement programme as stated in the Atkins Engineering report and is most efficiently delivered as part of the Telecoms equipment refresh works.

The revised costs are based on T1 actuals where available, supplemented with supplier and unit costs from our EHub and are summarised in the table below.

	Dec 2019 BP Submission (£m)	Ofgem Draft Determination (£m)	Proposed Final Determination (£m)
Fibre-Wrap Replacement	78.0	62.1	37.1
Telecoms Equipment Refresh	77.4		77.4
High Bandwidth Overlay	19.8		19.8
Control Telephony Refresh	8.0		8.0
Performance & Security Enhancements	3.7		3.7
Total	**186.9**	**62.1**	**148.0**

PCD 13 – Substation equipment (NLR)

We disagree with Ofgem's proposal to not allow a PCD for Substation Equipment. Throughout the consultation on NARM with Ofgem, within the ET sector working groups and Cross-Sector working groups extending NARM to include more non-lead assets was discussed, agreed and included in Ofgem's sector specific methodology decision document. We have therefore proposed to create a NARM output for our substation assets within T2. This includes Instrument Transformers, Through-Wall Bushings and Bays.

Ofgem have proposed to reject this PCD as, in their view, the underlying level of data NGET presently holds is not sufficient to enable monetised risk to be fully considered. Whilst we agree with this current position, which reflects why we could not develop NARM now, we are committed to working with Ofgem to develop these areas and transition to NARM before the end of the T2 period.

The PCD proposed in this area provides further protection for Ofgem by ensuring there is a measurable output to be delivered for our substation assets, hence this decision should be reversed for final determination.

PCD 14 – Protection and Control (NLR)

We disagree with Ofgem's proposal to not allow a PCD for Protection & Control. Throughout the consultation on NARM with Ofgem, within the ET sector working groups and Cross-Sector working groups extending NARM to include more non-lead assets was discussed, agreed and included in Ofgem's sector specific methodology decision document. We have therefore proposed to create a NARM output for our Protection & Control assets within T2.

Ofgem have proposed to reject this PCD as, in their view, the work scope is uncertain. Through bilateral engagement with Ofgem since publication of DD, we have identified that Ofgem did not take into account the detailed P&C information provided through the SQ process (SQ180). In addition, we have now provided detailed P&C supplementary evidence to Ofgem, which we understand is much closer to their requirements.

Protection & Control is an area which Ofgem have feedback their concern over the deliverability of the increasing volume of work necessary to maintain a reliable network. Defining an output for this area (which our proposed NARM output will do) will provide Ofgem with suitable protection against over or under-delivery of work in this category.

The PCD proposed in this area does not provide certainty around the work scope (the supplementary evidence does that), but does provide certainty around the delivery of the work. We therefore propose that Ofgem agree this PCD within Final Determination to provide the level of certainty required in delivery in this asset category.

PCD 15 – Protection and Control Coordination (LR)

See response for PCD 2 'Maintaining security of supply as the energy system changes' as this is a duplicate output.

PCD 16 – Overhead line (OHL) steelwork replacement (NLR):

We disagree with Ofgem's proposal to not allow a PCD in this area. In T1 we delivered an ambitious innovation programme recovering Grade 4 steelwork, which originally would have been replaced. Of the grade 4 steelwork traditionally replaced we recovered 60% at a lower cost. We have embedded these savings in our T2 plans, and have proposed a PCD in this area to continue incentivisation to embed this innovation, and provide certainty against delivery of the output. We have separated the steelwork replacement PCD (PCD 16) with the refurbishment PCD (PCD 17) to ensure each individual area of steelwork replacement and refurbishment is delivered.
We propose that Ofgem agree this PCD within Final Determination to provide the level of certainty around delivery, and incentivisation to deliver the output at a lower cost.

PCD 17 – OHL steelwork refurbishment (NLR):

We disagree with Ofgem's proposal to not allow a PCD in this area. We refurbish our steelwork through an ongoing process of tower painting (similar to the forth bridge). This is an ongoing programme which must maintain its run-rate to prevent reliability issues in the future. We delivered on target in T1, and propose to do the same in T2.
We have proposed a PCD in this area to provide Ofgem with protection and certainty against delivery against our tower painting programme. It is not viable to turn towers into lead assets (yet) hence this PCD provides an interim output.

We propose that Ofgem agree this PCD within Final Determination to provide the level of certainty around delivery in T2.

NGETQ6 Do you agree with our proposed approach to facilitating NGET's transition to an EV fleet?

Yes we agree with the proposal and welcome Ofgem's support of this commitment to Electric Vehicles, however clarification is sought over the model used for price parity as we understand the model used relates to car price parity and not commercial vehicles.

We do not agree however with the reduction of the requested capex of £20.6m down to £17.3m and have concerns over our ability to manage our operational fleet given Ofgem's proposed reduction in capex and opex associated with the diesel fleet. This response is also relevant to NGETQ13, reference from the DD consultation text '3.36 For Vehicles and Transport costs, we used a historical trend model based on RIIOET1 actual incurred costs for non-electric vehicles. We then multiplied the model's output by the proportion of the fleet that is not being replaced with electric vehicles (EVs)'. We believe the trend model used does not truly reflect the 40% of ICE vehicles that we are proposing to replace during the RIIO2 period. As indicated in our submission, the 40% is composed as follows : 26% 4x4 vehicles, 7% large <3.5 tonne drop-side/tippers, 4% Heavy Goods Vehicles between 4.6 tonnes and 16+ tonnes, 2% medium-panel vans with all-wheel-drive, and 1% large-panel vans with on-board power. The 40% of diesel vehicles cannot at this point be transitioned to EVs given that there are no commercially available electric equivalents. We believe the Ofgem model used is based on an average vehicle pricing model which includes small, medium and large panel vans which will distort the average pricing as they are not an equivalent replacement.

NGETQ15 on page 75 of the NGET DD consultation, relevant consultation paragraph on page 71 for CAI opex costs. A mitigated reduction in cost efficiencies could be considered if we fully understood the rational used by Ofgem to achieve the figure of £3.6m as we realise vehicle efficiency may improve with the move to EVs resulting in lower Opex costs. We don't understand the volume reduction and need further information on the model used to reach this figure as market benchmarking indicates costs will increase. National Grid submitted costs were based on actual Opex cost for fuel and maintenance associated elements as requested. National Grid secured lower than market average maintenance labour and parts pricing throughout the RIIO1 period to keep vehicle OPEX cost relatively low and stable, this benefit has now expired. Prior to and throughout the RIIO1 period National Grid have utilised a fleet management contract with negotiated T&C,s and annually reviewed fixed pricing matrix for Labour, Parts, FM Fees, Hires and Statutory tests with options to extend for a fixed term through a single supplier, the contract and associated extensions end in March 2021. We are aware that costs incurred over the last two years of the contract have been held below the market rate by the supplier. A new consortium purchased the supplier in 2020 and immediately assed the operating model and revised the pricing matrix for new contracts and extensions from 2021. National Grid have benchmarked the market place and have established the incumbent supplier still provides the best service and cost model however their revised operating model will increase associated fleet costs to National Grid by approx. 10% pa (circa [redacted]) from March 2021. For comparison the Motor Transport Annual operating cost tables reflect an average market growth of 13.58% between 2014 and 2018 for fleet maintenance based on pence per mile, National Grid have been unable to retain the lower pricing we experienced throughout the previous contract term as it is no longer commercially viable for the supplier base.

Source of Data - Motor Transport operating cost tables, widely regarded as the most reliable and accurate measure of the costs of running commercial vehicles https://motortransport.co.uk/annual-cost-tables/ summarized below for panel vans.

Vehicle type	1.6T	2.1T	2.8T	3.5T
Payload	**550kg**	**750kg**	**1t**	**1.4t**
Total (p/mile)				
2018	17.1	18.9	22.6	26.4
2017	14.9	16.5	19.7	23
2016		15.4	18.6	21.7
2015		15.4	18.6	21.7
2014	14.7	16.4	19.4	23
% increase	14.04	13.23	14.16	12.88

The proposed volume reduction of £4.2m and £3.6m equates to a reduction of 44.3% in Operating cost over the RIIO2 period which based on current discounted operating costs and National Grid fleet size is unachievable without fully understanding the model used for the proposed volume reduction.

NGETQ7 Do you agree that there is a need for a SF6 asset intervention PCD, and do you agree with our rationale for making this mechanism a PCD rather than a UM?

Yes we agree with the SF6 asset intervention being primarily managed under a PCD, for the majority portion which can be defined at the start of the price control period. In our opinion however, the required flexible portion, which takes account of the work required to abate the forecast emissions, the ex-ante unit cost allowance approach is more akin to an automatic adjustment UM. We have defined this split within our supplementary evidence pack as 55% of emissions to be covered under the fixed portion and 45% to be covered under the flexible portion.

NGETQ8. Do you agree with our proposals on the CVPs? If no, please outline why.

Please see our response to Core question Q35 on the BPI. This covers our view on Ofgem's proposals for NGET's CVPs.

NGETQ9 Do you agree with our consultation position to accept (subject to eligibility) NGET's caring for the natural environment CVP? Do you agree with our proposal to re-quantify the value of the CVP?

We agree with Ofgem's proposal to accept NGET's caring for the natural environment CVP. This CVP involves us committing to increasing the natural capital value of all our non-operational land by 10% during the T2 period at no additional cost to consumers. The commitment is from a 2020-21 baseline.

This CVP has a lot of stakeholder support:

- ☐ We have had positive feedback from the Natural Capital Coalition that setting our baseline and achieving a 2% annual target [a 10% improvement over 5 years] is an ambitious first step for T2.
- ☐ The independent user group considers our 10% improvement target is more stretching than other organisations have and that our target stands out as good practice.
- ☐ In its letter of 25 October, the RIIO-2 challenge group mentioned "proposals to support local communities through [...] improving assets or local spaces" as one of the three of our CVP areas where it thought we were "potentially delivering additional value". In its final report the RIIO-2 challenge group stated "As regards improvements to natural capital (where NGET is targeting a 10% increase in environmental value of non-operational land over RIIO-2, with outperformance over 10% recognised under the Environmental Scorecard ODI) [...] we think that the best proposals across the sector may warrant recognition but that these will need to be benchmarked carefully" (page 124)
- ☐ Citizens Advice supported this CVP on the basis that we were clear on why a 10% improvement in natural capital value is stretching and why it is going beyond business-as-usual activities.

We are already working with the Ofgem team to help them understand our sector-leading natural capital tool that we used to produce the CVP valuation. Frontier Economics checked our CVP calculation for our business plan. Our estimates of natural capital values are 30-year NPV calculations in line with best practice, but to be conservative for CPV purposes, where any CVP reward might need to be clawed back, we thought a 10-year NPV would be more appropriate. As a result, Frontier Economics adjusted our CVP by a factor of 45.2% based on the HM Treasury social time preference rate to produce our business plan CVP of £14.67m. We look forward to continuing to work with the Ofgem team on our CVP calculation for natural capital.

We understand from our engagement with Ofgem during the consultation period that SHE-T's CVP relates to biodiversity net gain rather than natural capital improvements as ours and NGGT's do. Therefore, there is no need to develop a common methodology between SHE-T, NGGT and NGET for natural capital. (Note: we are already working constructively with Ofgem, NGGT and SHE-T on our approaches to biodiversity net gain for SHE-T's CVP and ours and NGGT's environmental scorecard ODIs, which include a metric on biodiversity net gain.)

NGETQ10 Do you agree with our proposal to reject NGET's SO:TO optimisation CVP?

We disagree with Ofgem's proposal to reject NGET's SO:TO optimisation CVP.

Please see our answer to NGETQ4 above, which covers NGET's SO:TO optimisation CVP as well as the TOs-ESO joint paper on proposals to reduce constraint costs, which is closely related to NGET's SO:TO optimisation CVP.

Quality of outage management ODI

Ofgem did not ask a question about our "quality of outage management" bespoke ODI in its DD, so we are responding to Ofgem's views on this ODI here.

Ofgem did not include any analysis of our quality of outage management bespoke ODI (from page 25 of our NGET RIIO-2 business plan and pages 23-26 of our NGET RIIO-2 business plan ODI annex) in the DD that Ofgem published on 9 July. We reminded Ofgem about this ODI in an email on 13 July 2020. Ofgem included analysis of this ODI in its errata list on 17 July 2020 and its reissued DD NGET document on 17 July 2020.

Ofgem states:

"We are proposing to reject this ODI because we note that this customer group (customers affected by outages) has been captured in the Quality of Connections target audience and common milestones. We have worked with the TOs to collectively develop the common milestones and trigger points at which we propose the survey will be issued and the target audience that this survey will capture. We consider that NGET will be sufficiently incentivised to improve vital repair work services through our proposed Quality of Connections common ODI-F" (Table 10, page 13 DD NGET annex).

We explained in our NGET RIIO-2 business plan annex ET06 on ODIs, page 23, "If Ofgem includes all our customers affected by outages in its common ODI, we expect not to take forward this bespoke ODI." Ofgem has not yet concluded on the coverage (or "target audience") for its quality of connections common ODI, but Ofgem is consulting on the TOs' joint proposal for the target audience, which includes customers affected by outages under "generation or demand customers who are: [...] Connected to the transmission system or a distribution system and impacted by transmission activities." (page 86, Ofgem DD ET annex) and under the milestone "E. Outage Management" (page 85, Ofgem DD ET annex).

If Ofgem takes forward the milestones and target audience for quality of connections ODI that it is consulting on in its DD we agree that our bespoke ODI is not required. However, the wider scope of the quality of connections ODI than Ofgem included in its SSMD will mean that the size of the common ODI should be considerably higher than the 0.4% of base revenue that Ofgem is currently assuming.

If Ofgem decides to exclude customers affected by outages or the outage management milestone from its final determination on its quality of connections common ODI we strongly request that Ofgem reinstates our quality of outage management bespoke ODI because it reflects the importance of outage management for our customers. As we explained in our RIIO-2 business plan ODI annex our customers have told us through our stakeholder engagement that we can still improve the way we communicate and manage outages.

NGETQ11 Do you agree with our proposed allowances in relation to load related capex? If not, please outline why.

The load related capex elements of the business plan we built with our stakeholders is comprised of projects that ensure it is easy for our customers to connect to and use our network and enable the transition to net zero; minimising the cost of the transition and ensuring the network stays resilient against these changes.

Allowances for capex are split into baseline allowances and the unit cost allowances used for volume driven uncertainty mechanisms. Whilst there are some overlaps between these two aspects of the Draft Determination our response to this question focuses on baseline allowances. Our response on the common sector generation & demand and reactor unit cost allowance can be found in response to questions ETQ13B and ETQ13C of the Electricity Transmission Annex and NGETQ17 focuses on our response on the boundary capability uncertainty mechanism.
We do ***not agree*** with all proposed allowances in the Draft Determination for load-related CAPEX and set out our concerns at both a plan and cost category level, as follows:

Plan level

1. Overarching concerns, impact on baseline allowances and recommendations
2. Comments on unit cost efficiency and project cost assessment

Cost category level

3. Detailed comments on each aspect of our load related plan.

1. Plan level – Overarching concerns, impact on baseline allowances and recommendations

After some further clarification from Ofgem, we were able to recreate Ofgem's view of requested capex of £1,110m (net of indirect costs) against Ofgem's Draft Determination of £891m (net of indirect costs). The table below shows the full breakdown of our submission, the impact of the issues we highlight below, and the adjusted allowances proposed once these issues are rectified.

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
i.	Generation and demand connections	Local Enabling (Entry)	181.3	137.4		42.9		180.3
		Entry Sole Use	24.6	24.6				24.6
		Local Enabling (Exit)	74.9	44.4		25.7	60.6	130.7
		Exit Sole Use	45.3	36.4		8.9		45.3
ii.	Boundary capability	Wider Works	427.4	292.6		20.2	235.7	548.5
iii.	LOTI pre-construction	Wider Works	152.5	152.5	-89.0		308.6	372.1
iv.	Easements	Wider Works	78.3	78.3	-12.5		12.5	78.3
v.	Reactors	Wider Works	25.8	25.2	-4.6	5.2		25.8
vi.	Site separation	Wider Works	34.8	34.8				34.8
vii.	Protection and control	TSS Infrastructure	26.1	26.1	-22.2		5.0	8.9
viii.	System monitoring	TSS Infrastructure	38.9	38.9				38.9
	Sub-total:		1109.8	891.2	-128.3	102.9	622.4	1488.2
	Efficiency		-30.5					-30.5
	Total:		1079.3	891.2	-128.3	102.9	622.4	1457.7

We do ***not agree*** with proposed allowances for load-related CAPEX for the following summary reasons, which we expand on in sections 2 and 3 of the response to this question:

a. ***We have identified <u>factual errors</u> in Ofgem's draft determinations which would reduce allowances by £128.3m***

Ofgem have not correctly used the detail provided in the formal submission, SQs and BPDTs which has resulted in incorrect proposed allowances being published. There are also inconsistencies both within individual documents and across the various documents and models that together comprise the Draft Determination, for example:

- ☐ Tables 19, 20, 21, 22, 23 and 24 have errors in addition and do not match allowances in Table 18 of the NGET Annex.
- ☐ Proposed allowances as set out in Table 18 of the NGET Annex do not reflect decisions set out elsewhere in the document, such as the Table 17 statement that "We have removed £14.9m from Baseline" in relation to Easements.

Ofgem should correct the errors and inconsistencies between the narrative in the Annex and the proposed LRE allowances

b. ***We believe there are <u>methodological errors</u> in the approach to unit cost efficiency and project cost assessment which would increase allowances by £102.9m***

We have identified issues in how:

- ☐ Efficient unit costs have been calculated.
- ☐ Efficient unit costs have been applied to total project costs.
- ☐ The lack of availability of comparable unit costs has been dealt with.
- ☐ The assessment of risk and contingency estimates contained within our allowances.

Ofgem should reinstate our proposed allowances for all schemes where they agree the need case has been justified

c. ***We have <u>new information</u> about ESO and customer requirements which would increase allowances by £622.4m***

Updating the baseline to reflect the latest ESO and customer requirements will allow us to deliver projects with confidence, minimise reliance on uncertainty mechanisms and have a positive effect on financability.

- ☐ Ofgem have updated our baseline allowances for boundary capability and LOTI pre-construction by removing projects not signalled as proceed in NOA5 but have not updated the baseline allowances to add new projects with a proceed signal.
- ☐ Allowances for generation and demand projects allowed in the baseline need to be updated to reflect latest scope following changes to customer requirements.

Ofgem should update baseline allowances to reflect changes in requirements since submission e.g. NOA5 impacts and customer requirements

d. ***We require <u>clarity</u> on how baseline allowances interact with the broader framework which may or may not require an adjustment to allowances***

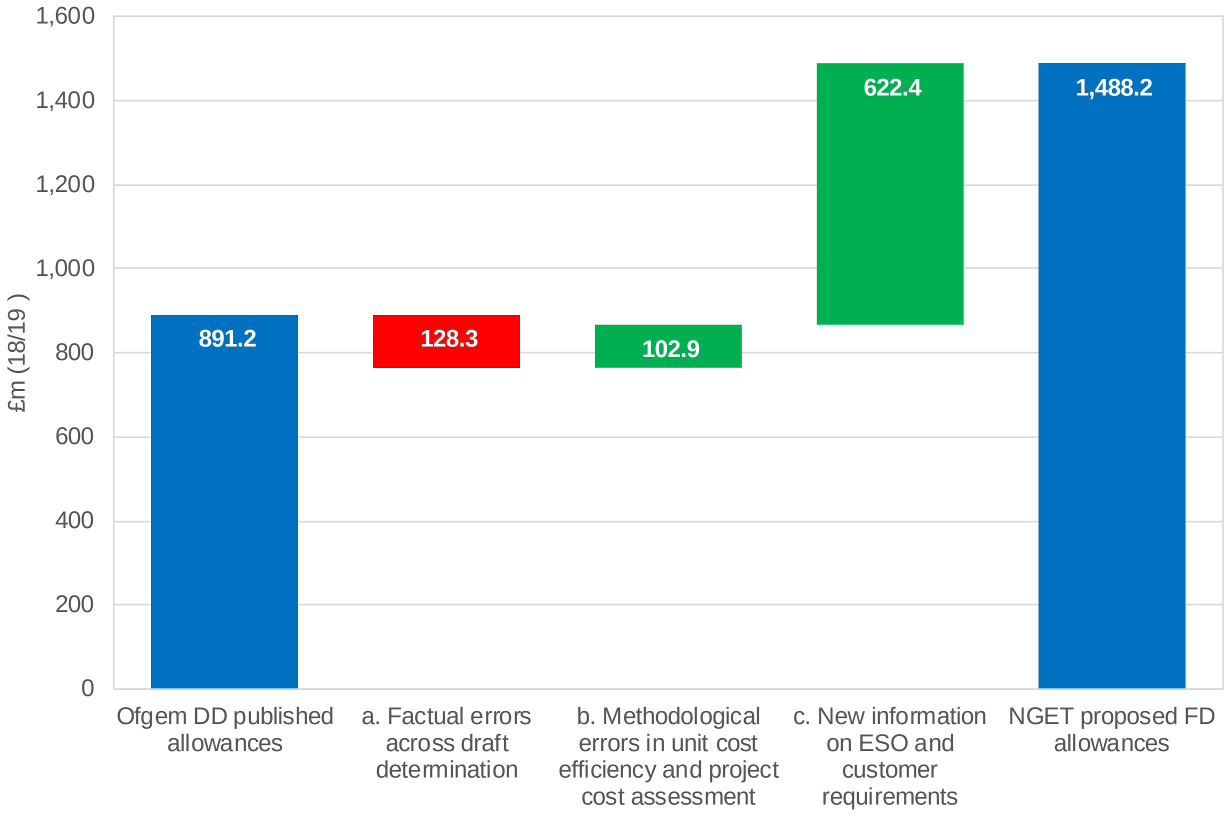
It is challenging for us to assess the impact of baseline allowances in the draft determination without further clarity on how they will interact with the broader framework proposed. We seek clarity on:

- The approach to the bridging fund for projects with outputs beyond T2.
- The approach to funding expenditure in T1 that delivers outputs in T2 (previously called WIP), which we understand could be dealt with in T1 close-out where not covered in the DD.
- An inconsistency in how the demand connection output is defined between baseline allowances and the volume driver mechanism that will adjust allowances over T2
- How Ofgem propose to adjust baseline allowances in the ex-post true ups proposed across most of our baseline plan (also covered in our response to ETQ8). These ex-post assessments remove the drive for efficiency and innovation, increasing costs for consumers.

Ofgem should urgently provide clarity on the how allowances will work in the context of the broader price control

It is critical that the adjustments to baseline allowances set out above are made to the load-related elements of our plan so that we can deliver for our customers and consumers and are efficiently financed to do so.

The chart below shows how these areas contribute to the proposed allowances of £1,488.2m excluding capitalised Indirect costs. We provide further detail on our concerns in sections 2 and 3 of our response to this question.



*Point C – Does not include any allowances for: (i) pre-construction activity for the customer trigger projects that are >£100m (II) Demand scheme Harker as we are working with Ofgem to determine the appropriate route to fund this project as cost for the solution are now >£100m.

2. Plan level – Comments on unit cost efficiency and project cost assessment

We have identified issues in the (i) calculation of efficient unit costs, (ii) application of efficient unit costs applied to projects to calculate project allowances, (iii) the lack of availability of efficient unit costs, and (iv) the assessment of risk and contingency estimates contained within our allowances.

i. Incorrect calculation of a benchmark efficient unit cost

In summary, our analysis shows that Ofgem have incorrectly calculated efficient unit costs through:

- a lack of clarity in the BPDT and associated guidance leading to companies submitting and reporting costs in an inconsistent manner
- not considering underlying differences in detailed scope between Load and Non-Load related investment, and historic (T1) and forecast (T2) weighted averages
- disaggregation of project costs into component parts not necessarily giving a clear view of the realistic, efficient cost of delivering whole projects
- failing to recognise appropriate differences in scope within a simple unit cost category

The benchmark unit costs for use in the Project Assessment Model have been derived from:

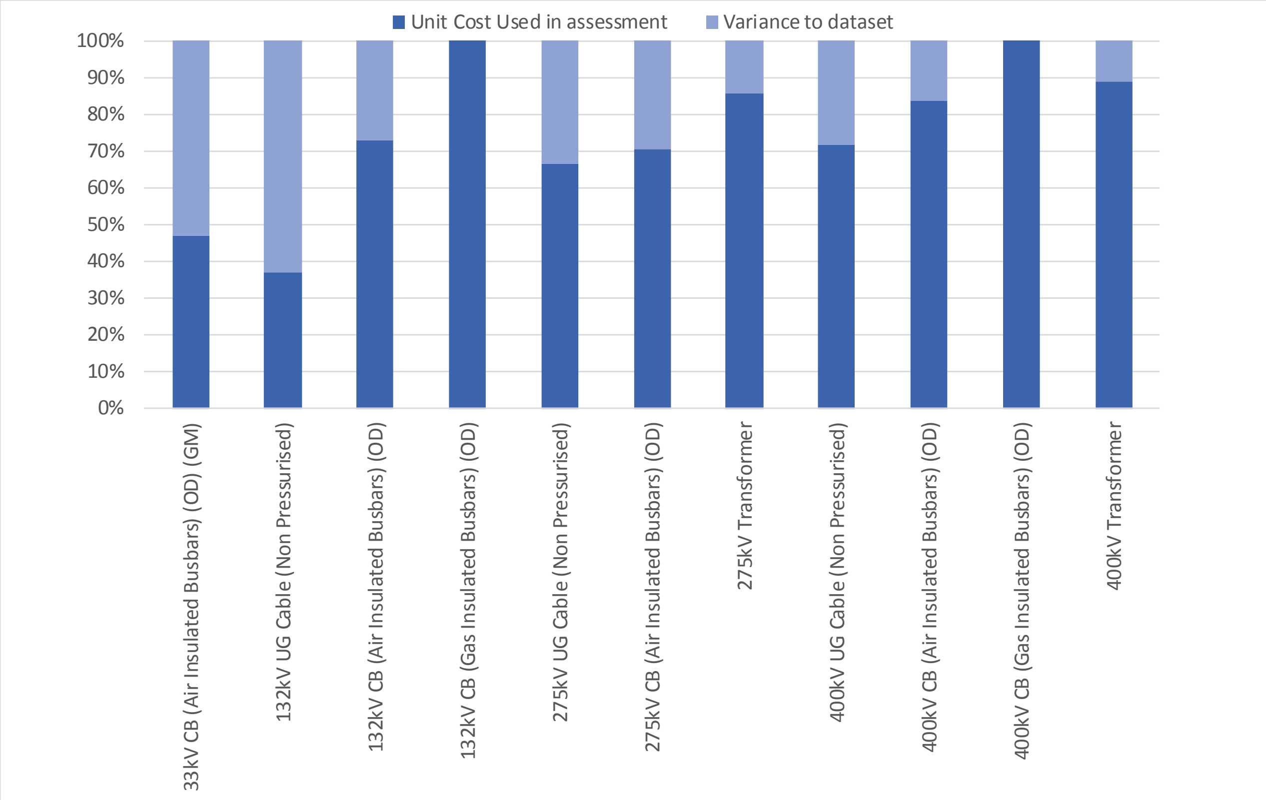
- both Load and Non-Load projects; the former tends to include establishing new infrastructure or uprating assets to meet a load-related driver while the latter is dominated by replacing existing assets (often in situ, re-using existing civils).

Ofgem have then set a single value for the efficient unit cost covering both Load and Non-Load portfolios. This approach is not appropriate as it does not recognise the natural variance in cost across different projects within a portfolio and sets an unrealistic allowance based on a unit cost which reflects none of the actual input unit costs.

- are drawn from across all three TOs. As a result of a lack of clarity in guidance, different TOs have treated cost components in different ways. Consequently, Ofgem's methodology removes some efficient costs (e.g. civils). This has materialised in the data sample used by Ofgem to determine the efficient unit cost, leading to errors.
- direct asset costs such as transformers and non-asset costs such as civils. Indirect costs such as design, network planning and project management are assessed separately being (wrongly) classed as Indirect Opex. This approach prevents true calibration to historic performance and across companies because different delivery models will result in a different split between direct and indirect costs while the gross cost may be identical. Therefore, Ofgem's approach does not consistently assess the full cost of delivering schemes.
- a single unit cost per asset class and voltage. In many cases, this is overly simplifying the unit cost categorisation and incorrectly disallowing efficiently incurred costs. The chart below shows the National Grid Load submission for 400kV AIS Circuit breakers. The dataset shows multiple peaks associated with the installation of additional circuit breakers in existing bays at the lower end of the cost envelope against the installation of a new circuit breaker and all associated ancillary equipment at a new substation, with a far greater associated unit cost. These are not comparable units but have been combined into a single average cost.

[redacted]

- Taking the lower of T1 or T2 averages for the dataset reported. This approach fails to recognise genuine changes to cost drivers (e.g. legislative changes) and input costs over the 15 years spanned by projects in the data set. The chart below shows the efficient unit cost assessed by Ofgem for units in our T2 Load-related plan and the variance to the alternate dataset, i.e. if the selected benchmark is the T1 weighted mean the alternate dataset is the T2 weighted mean, and vice versa.



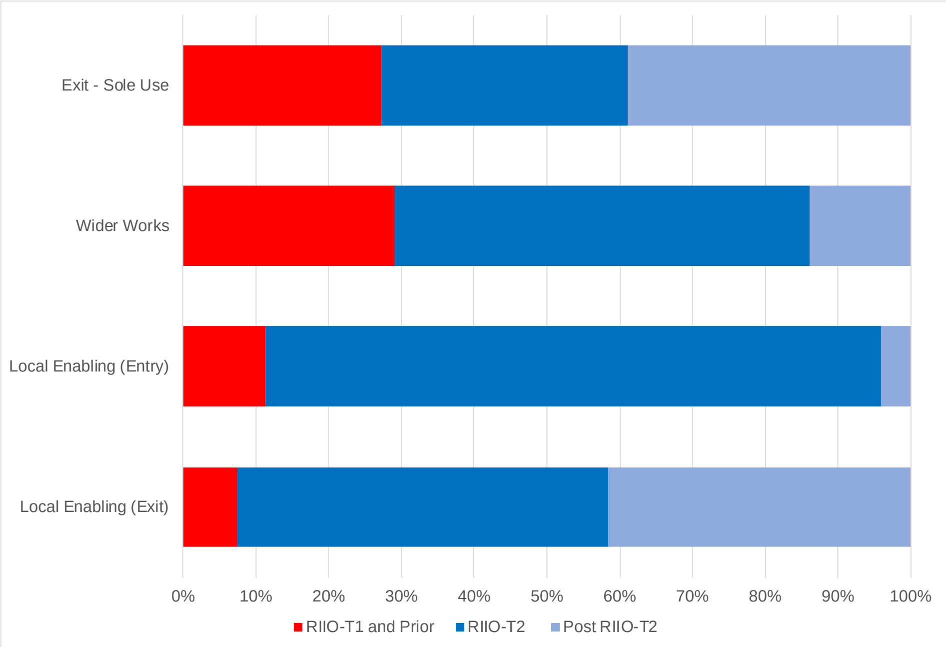
Most of the resulting benchmark unit cost values do not appear statistically robust; most have large standard deviations (sometimes in excess of 100% of the weighted mean, suggesting that negative unit costs are possible). This is likely to be driven by small sample sizes and the aggregation of differing scopes within a single unit cost value.

The chart below shows the total T2 value by unit submitted in our plan and the proposed allowances suggested at Draft Determination.

[redacted]

ii. Application of efficient unit costs applied to projects to calculate project allowances

The unit cost assessment has been undertaken based on full project costs. This assumes that units are delivered equally across the phasing of a multiyear project. It does not take into account where an investment may already be contracted and there is no opportunity to achieve an efficiency. It also results in a project table that restates historic costs for a project, in some instances before the start of RIIO-T1. The chart below demonstrates the application of cost assessment with values in red showing where an efficiency challenge has been applied to spend already incurred.



The approach taken has been to cap costs at the benchmark unit costs, but where submitted costs are below the average these are retained. This perversely rewards TOs whose costs are consistently higher than the average as the resulting allowance would be the efficient unit cost as opposed to a true portfolio with items above and below the efficient unit cost. As an approach, it does not recognise the natural spread of costs that would exist in a price control period and variation in nature of projects.

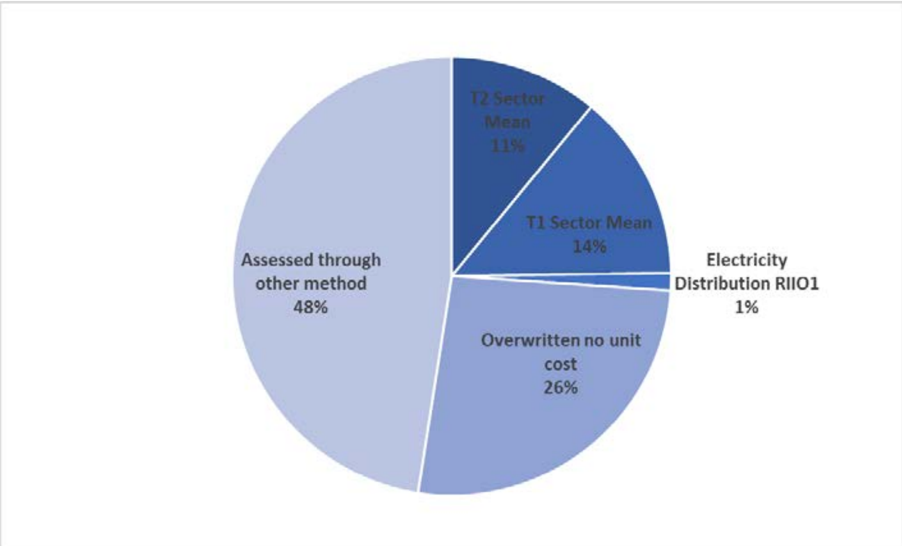
The chart below shows the impact of this capping on the 400kV transformers portfolio within NGET's Load plan. Ofgem's efficient benchmark for these schemes is [redacted]. Across NGET's proposed portfolio there is a small number of schemes that exceed this benchmark. However, the total portfolio has a weighted average cost of £[redacted] (i.e. below Ofgem's benchmark). NGET believes this represents the expected spread of costs that would be expected across a range of schemes with differing site-specific requirements within the portfolio. Ofgem's approach is to assess projects on an individual basis and reduce the proposed allowance wherever the benchmark cost is exceeded. This approach removes £[redacted] from NGET's portfolio allowance and further reduces NGET's already-lower-than-the-benchmark average unit cost to £[redacted], 10% below the assessed efficient unit cost. We believe this approach is not appropriate as it does not account for justifiable individual project cost variances and the demonstrated overall efficiency at a portfolio level.

[redacted]

It is unclear why cost assessment has been undertaken on sole user connection assets. These costs and associated income are treated as an Excluded Service. The customer has a choice to build or source their own connection assets where they are able to do so at a lower cost. We believe this area of spend is regulated through the charging methodology approved by Ofgem. By including connection assets in the sample to assess efficient unit costs, this is not a like for like comparison as the costs for ancillary assets will differ between connection and infrastructure assets.

iii. The availability of relevant unit costs to assess our proposed investments

Ofgem state that they used historic costs as a valuable input. From our analysis, we can see that our plan has been assessed against the following benchmarks, with only 14% of the Load-related costs being assessed against relevant historic experienced costs (T1 Sector Mean).



iv. Approach to assessing risk and contingency within our allowances

Ofgem's systemic reduction of risk and contingency costs is overly simplistic (paragraph 3.27 of Sector Annex and 3.64 of NGET Annex). It is assumed that risk is incurred equally across all cost categories – asset, civils, other costs. Ofgem have removed any risk value apportioned to asset costs since these are benchmarked and believe that these include outturned risk values. This assumption is dependent on TOs consistently including risk in asset costs in their T1 and T2 data sets where appropriate.

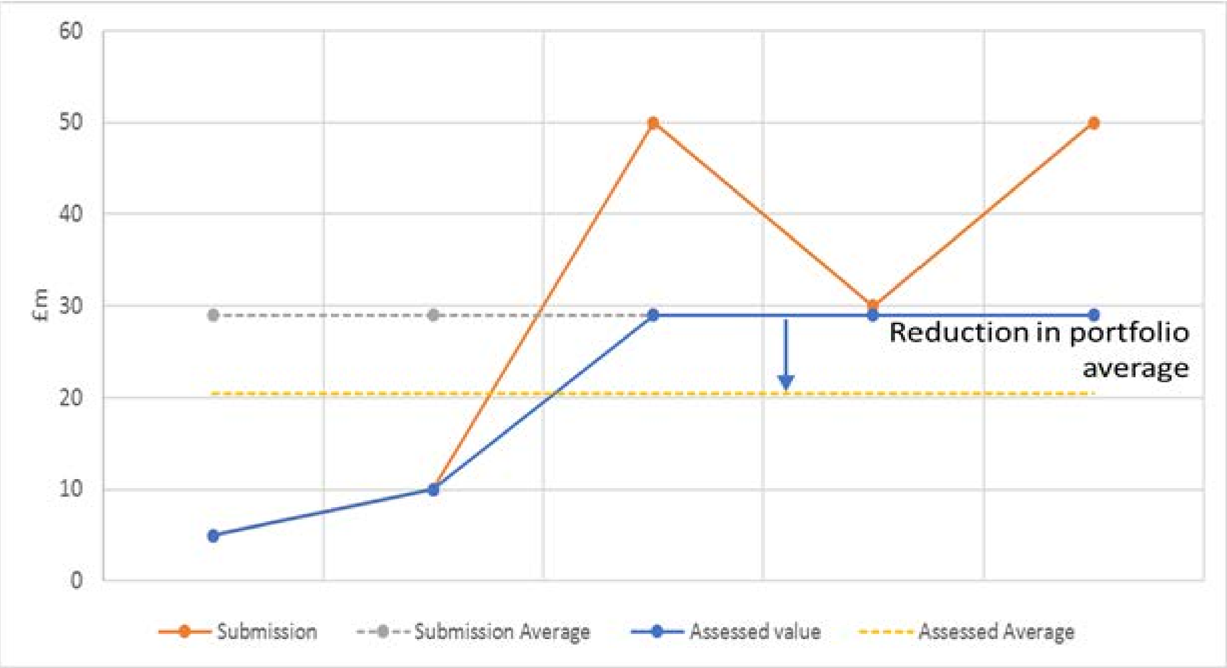
Any reductions as a result of cost assessment have been equally applied across all cost categories. However, a value associated with a particular risk event may only apply to one or two cost categories, for example contaminated ground conditions are likely to wholly impact civil costs. Where the risk would have impacted asset or indirect costs, which have been removed from the project for assessment purposes, the reduction is applied to the remaining cost categories in error.

Ofgem have assumed that all risk identified in a project is incurred in the T2 period – regardless of the phasing of a project (i.e. even if only a portion of total project spend occurs in T2). As such any adjustments following assessment of risk values have been applied entirely to the T2 allowances. This does not recognise projects spanning the T1-T2 boundary and the T2-T3 boundary. This approach has resulted in negative allowances in the T2 period.

Ofgem stated that risk was capped based on historic risk averages, but this is not reflective of the approach used in their calculations:

- Firstly, the average has been calculated on the submission sample not the historic average.
- Secondly, the cap has been calculated through simple averaging of project risk percentages rather than calculating a weighted average across the sample.
- Finally, in applying the cap, they have incorrectly applied the formula and so have not reduced projects to the calculated average risk %. Had this approach of capping at average been applied as Ofgem intended, it would result in TOs having allowances for risk that is lower than the average risk costs previously incurred.

The chart below is an illustration of the effect of capping values above average but retaining values beneath the average unadjusted.



1. Cost category level – Detailed comments on individual aspects of our load related plan

In this section we highlight errors, issues and new information that we recommend are considered in updating baseline allowances within each component of our load-related plan. These are subcomponents of the aggregated view presented in section 1 of our response to this question and the allowance impacts tally up between sections.

We present views on each component of our plan as follows: (i) generation and demand connections, (ii) boundary capability, (iii) pre-construction for LOTI projects, (iv) easements, (v) reactors, (vi) site separation, (iv) protection and control and (v) system monitoring

i. *Generation & demand connections <£100m*

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	Factual errors	Methodology errors	New information	NGET proposed FD allowances
i.	**Generation and demand connections**	Local Enabling (Entry)	181.3	137.4		42.9		180.3
		Entry Sole Use	24.6	24.6				24.6
		Local Enabling (Exit)	74.9	44.4		25.7	60.6	130.7
		Exit Sole Use	45.3	36.4		8.9		45.3
	Total:		**326.0**	**242.8**	**0.0**	**77.5**	**60.6**	**380.9**

We recommend the following errors, issues and new information are considered in updating allowances for generation and demand connections.

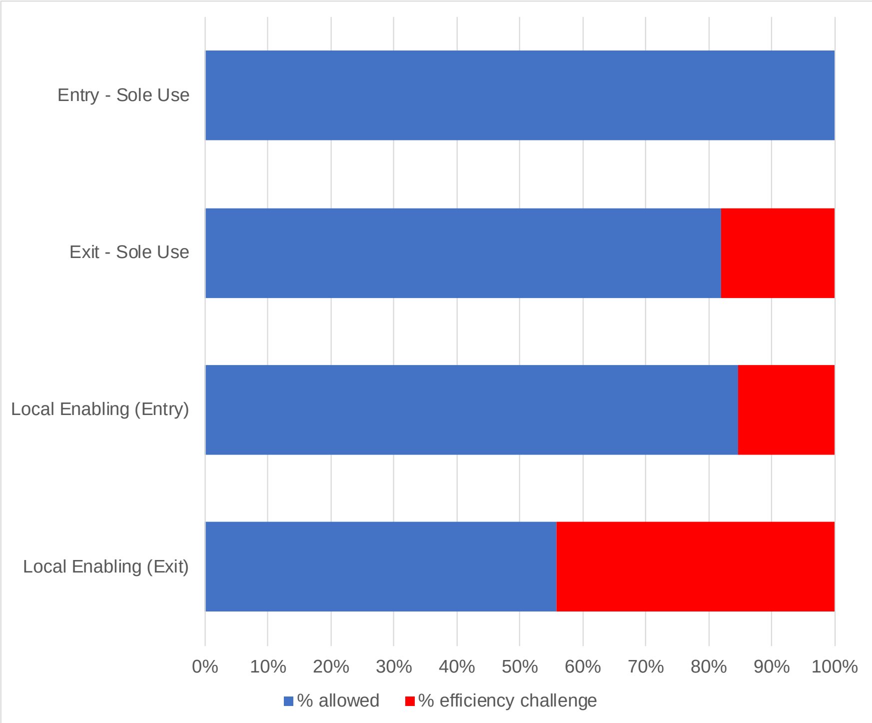
(a) Factual errors across the draft determination

We found no factual errors for this cost category.

(b) Methodological errors in unit cost benchmarking and project cost assessment process

Ofgem's methodology to establish efficient cost to connect generation and demand, using the lowest costs for all units, results in 'efficient costs' that do not provide allowances commensurate with the full cost of delivery of the project.

The chart below shows the proportion of submitted spend and how it has been treated in the cost assessment process.



The table below shows the differences between proposed allowances and our view of efficient costs required to deliver generation connections in our baseline plan.

Generation connection project disallowances

[redacted]

We provide project level detail below to show why unit costs have been inappropriately applied. For more information please see the review of cost assessment for Load-Related projects in the independent report provided by Mott McDonald.

[redacted]
The works comprise construction of a new 400kV AIS substation on a greenfield site to facilitate the connection of [redacted] offshore windfarms. Infrastructure has been reduced by adopting a quad tee connection arrangement, as opposed to full turn-in of the 4 existing feeder circuits. Due to this being a new build site there are various items of common site-level infrastructure which are required to enable a new substation to be put into service. This includes common protection and control equipment (e.g. busbar protection, substation control system), auxiliary supplies, telecommunication services, site

services (e.g. water supplies, drainage), civil infrastructure, electric fence, earth mat.

The volume of circuit breakers for this scheme has been reduced through the decision to create a quad-tee connection into the existing OHL, which reduced the infrastructure required of 10 CB bays compared to 14 bays for a full quad circuit turn-in.

3 x circuit 400kV cable connections are required to connect the new substation to cable sealing end compounds located at the OHL tower. We anticipate the 400kV cable cost per km to be higher as it is affected by:

- cable connections are of short length (200m) therefore the same cost efficiency does not apply as for multiple km cable sections
- termination costs are included within the cable costs, due to short length of cable the costly terminations significantly increase the unit
- 2 cables per phase are included due to thermal rating, which again increases the number of terminations within the unit cost

[redacted]

Whilst this is not a new build, this project does require extensions of the existing substation and bay and site level P&C works (i.e. SCS database changes) in addition to civil works including fence and earth system.

Extension of the site to the east triggers the need to underground existing 132kV OHL located on the east perimeter.

The connection of 2 x OFTO bays does not result in a CB volume (as these will be OFTO owned), however infrastructure works are required by NGET to connect these bays including AIS busbar extensions, and P&C works including extension of busbar protection, substation control system in addition to operational tripping scheme works. These costs are included within the 400kV CB volume increasing the unit cost for the scheme.

[redacted]

The works comprise construction of a new 400kV, 6 bay double busbar GIS substation ([redacted]) and 2.8km of new double circuit overhead line to connect the substation to the network. This solution has been fully developed and costed and is ready to progress to delivery when the customer confirms their intent to proceed.

Due to this being a new build site there are various items of common site-level infrastructure which are required to enable a new substation to be put into service. This includes common protection and control equipment (e.g. busbar protection, substation control system), auxiliary supplies, telecommunication services, site services (e.g. water supplies, drainage), civil infrastructure, electric fence, earth mat.

Due to the additional power being added to the network, further works are required at [redacted] substation to transfer a feeder circuit from one side of the substation to the other. This to avoid overloading the substation and requires a length of high voltage cable to divert the incoming feeder to a new bay which will be built as an extension of [redacted] 400kV substation.

[redacted]

The works comprise construction of a new 400kV, 4 bay double busbar GIS substation ([redacted]). Infrastructure has been reduced by adopting a tee connection arrangement to the overhead lines, as opposed to full turn-in of the existing feeder circuits. Due to this being a new build site there are various items of common site-level infrastructure which are required to enable a new substation to be put into service. This includes common protection and control equipment (e.g. busbar protection, substation control system), auxiliary supplies, telecommunication services, site services (e.g. water supplies, drainage), civil infrastructure, electric fence, earth mat. While this connection is for a [redacted] generator, as a full new substation was the only feasible option the costs are considerably higher than average for the connection of similarly sized generation projects.
[redacted]
The scheme was competitively tendered so represents actual contractor/NG costs, with a current predicted cost for the scheme of £[redacted] and is mostly complete. The project has a number of complexities which increased unit costs, notably the works required converting an already operational substation into a full double-busbar substation by populating partially populated skeleton bays with full plant and equipment. The site being operational placed significant construction challenges for both civil and primary works including various proximity outages and a complex outage/construction sequence to reconfigure the site in stages to achieve the final arrangement.
[redacted]
To facilitate the connection of [redacted] the following works are required at [redacted]: - installation of Reserve Section Breaker in the partially populated bay - extension of the operational fence line and substation platform, raised to 1:1000 flood risk level - all associated environmental, ecology, temporary works, including modifications to the haul road - extension of the Main and Reserve sections 1 & 2 for [redacted] to connect. The scheme is currently out to competitive tender, with initial returns showing higher than our submitted estimates.

The table below shows the differences between proposed allowances and our view of efficient costs required to deliver demand connections in our baseline plan.

Demand connection project disallowances

[redacted]

[redacted]

We provide project level detail below to show why unit costs have been inappropriately applied. For more information please see the review of cost assessment for Load-Related projects in the independent report provided by Mott McDonald.

[redacted]
The scope of this project is to extend a mesh corner to accommodate a new 275/132kV SGT and associated HV and LV bays. All the assets are new and the solution requires the extension of the substation site on to surrounding land which requires extensive cut and fill. This connection is complex due to the additional scope required when extending a mesh corner, including the modification of the downleads of an incoming OHL feeder circuit and provision of a new gantry, two HV circuit breakers and HV cabling to re-connect the feeder to the 275kV substation.
[redacted]
In order to facilitate this connection, a new grid supply point has to be established and as such a significant amount of infrastructure works are required. At the point of our business plan submission the scope was understood to be the following: - OHL Tee connection, requiring an additional terminal tower - Construction of a cable sealing end compound and HV cabling connection to substation compound - Construction of a new 400kV single switch mesh substation The unit cost allowances include for the provision of a number of ancillary assets that are required in order to support the lead assets. On establishing new site assets such as LVAC supplies, surface water drainage, earth mat, fibre connections, oil interceptors, cesspit, fencing, site welfare facilities are required. Supporting assets such as these drive up unit cost allowances when establishing new substations.
[redacted]
To enable the connection of a new SGT a new tee off from an existing 275kV overhead line is required. This drops into a vacant space next to the existing substation compound. NGET propose to install an additional circuit breaker and associated bay equipment whilst extending the substation compound. There is also a short run cable section and the requirement for terminations.
[redacted]

[redacted]

We recommend that Ofgem reinstate our proposed allowances for all schemes where they agree the need case has been justified

(c) New information about ESO and customer requirements

We are of the view that baseline allowances should be updated to include the following projects where scope and cost have evolved, for legitimate reasons, since our December submission. These changes would not be catered for by any of the proposed UMs, therefore we should update the baseline.

i. [redacted]

- ☐ Ongoing engagement on specific engineering design with customers and the market has led to changes in proposed scope and cost. Our December submission was based on the best available information and our latest view is now based on finalised customer decisions and detailed returns from contractors
- ☐ The costs, as a result of legitimate scope increase, have increased by ~90%
- ☐ On 20th August 2020, NGET submitted an updated engineering justification paper detailing the revised scope, design and associated costs.

ii. [redacted]

- ☐ Additional customer activity (Feb 2020) has increased the scope and cost of proposed works at Harker
- ☐ The preferred design now represents a single solution that meets multiple customer drivers at Harker as well as delivering environmental benefits in the form of SF6 asset reduction, the costs for this solution is now over £100m.
- ☐ We have been working with Ofgem to agree an approach to updating allowances for the Harker project where recent customer activity has significantly changed the scope and cost compared to our December plan. It has been proposed that the project will be managed through the LOTI process with pre-construction funding to be included in our baseline plan and all construction funding agreed through LOTI. On this basis we have removed the individual allowances for works at Harker that were requested in our December submission.

We also believe PCDs shouldn't restrict us from making genuine changes that meet the evolving needs of customers or where there is new scope for innovation and need to work with Ofgem to determine how would we be funded for such changes going forward.

(d) Clarity on how baseline allowances interact with the broader framework

i. Clarity is required on what Ofgem means by projects starting in RIIO-T1

- ☐ It is unclear how funding will occur if this refers to the initial point of investment, as there are many projects for which costs were incurred during T1 but subsequent customer delays have meant that we no longer expect to connect until after RIIO T2. Should these projects progress earlier than expected, it is unclear whether they would be funded, and if so, how Ofgem's use of project level PCDs will remove baseline allowances for any projects displaced by these projects,
- ☐ Alternatively, Ofgem considering a project as starting at a later point e.g. £m threshold, upon tender, sanctioning, commencement of construction;

Thus, potentially placing the timing of customer projects at risk, increasing costs to consumers and providing a perverse incentive to ensure funding under the uncertainty mechanism.

ii. Projects funded via the bridging fund for outputs beyond RIIO-T2 is subject to ex-post cost assessment, which will undermine the drive for efficiency and innovation, reduce TO confidence in funding and our ability to facilitate the many new customers that we expect to seek connections during T2 as we transition to net-zero.

Similar to the MSIP re-opener, the arrangements for funding investment required in RIIO-T2 to deliver outputs beyond the price control period will be subject to ex-post assessment (as part of the RIIO-T2 closeout process). The main differences are:

- The arrangements for projects spanning price controls is that an initial bridging fund allowance will be set that will be subject to an ex-post true-up. Whilst the issues concerning TOs' appetite to innovate and reluctance to invest due to lack of funding certainty remain, the latter will be slightly reduced compared to MSIP through the provision of up-front allowances offsetting some of the increased financing costs brought with increased investment risk.
- The bridging arrangement has no arbitrary financial threshold (although TOs could still face perverse incentives to delay projects subject to the RIIO-T2 volume driver into RIIO-T3, where resulting allowances are insufficient).

iii. We disagree with the use of secondary deliverables in PCDs to define outputs as the input set out in the relevant EJP (please see our response to ETQ05 that highlights our concern with this policy decision) as this adversely impact innovation and the flexibility on how we deliver which will have an impact on consumer benefit.

iv. Inconsistent application of the demand output in the Draft determination between schemes in the baseline and how these will be dealt by uncertainty mechanism.

- As a minimum both definitions must be consistent; as the output for the baseline scheme is based on No. of SGT or a new GSP as stated in table 39 of the NGET annex and the output for the uncertain demand schemes is based on £8k/MVA
- We suggest that the output for demand should be based on our proposed UM position as detailed in our response to ET13B.

ii. Boundary capability <£100m

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
ii.	Boundary capability	Wider Works	427.4	292.6		20.2	235.7	548.5
	Total:		427.4	292.6	0.0	20.2	235.7	548.5

We recommend the following errors, issues and new information are considered in updating allowances for boundary capability:

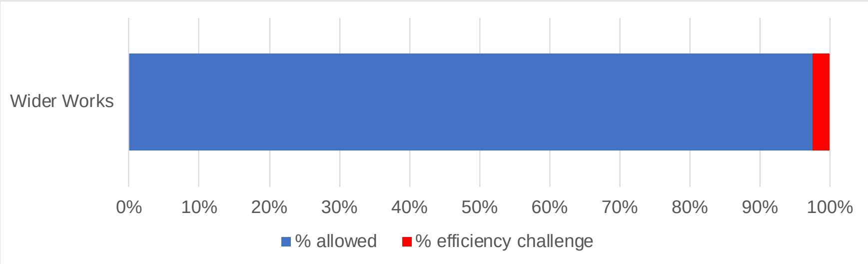
(a) <u>Factual errors across the draft determination</u>

We found no factual errors for this cost category.

(b) <u>Methodological errors in unit cost benchmarking and project cost assessment process</u>

Ofgem's unit cost benchmarking has removed some efficient costs (e.g. civils) as a result of TOs submitting costs in different ways (e.g. what is included in a unit).

The chart below shows the proportion of submitted spend and how it has been treated in the cost assessment process.



The table below shows the differences between proposed allowances and our view of the efficient costs required to deliver the schemes.

[redacted]

Further evidence is provided below at scheme level to show why unit costs have been inappropriately applied. For more information please see the review of cost assessment for load-related projects in the independent report provided by Mott McDonald.

[redacted]

[redacted]

(c) New information about ESO and customer requirements

The Network Options Assessment (NOA) 2019/20 published after business plan submission in January 2020, provides more up to date information on network reinforcements that provide consumer benefits.

Ofgem have updated our baseline allowances for boundary capability by removing the allowances associated with projects identified as not being part of the future optimal investment plan in the latest NOA but have not updated the baseline allowances to add the new boundary projects that are now recommended.

A further 27 boundary capability projects beyond those included in the December baseline were identified as being part of the optimal future investment plan and hence require investment in T2. We have provided engineering justification papers for each of the new recommended schemes, which detail the scope and cost drivers. We will also provide the necessary Business Plan Data Table updates to capture these updates.

The overall updated boundary capability investment proposed for T2 is as detailed in the investment decision pack Supplement to NGET_A7.02 Incremental Wider Works submitted to Ofgem on 24th August 2020 and summarised in the table, below.

	Projects in December submission (£m)	New projects recommended in NOA 19/20 (£m)	Total

T2 expenditure	369.7	282.8	652.5
Total investment	667	490.2	1,157.2

We recommend that Ofgem update baseline allowances for boundary capability to reflect all changes resulting from the latest NOA publication.

(d) Clarity on how baseline allowances interact with the broader framework

The introduction of secondary deliverables into PCDs alongside ex-post assessments will undermine innovation with new technology and with existing technology to the detriment of consumers.

This is particularly the case for boundary capability investments (multiple routes/sites where solutions can be delivered on a single boundary) where there is more potential for alternative and innovative solutions. An unnecessarily rigid PCD would impact our ability to deliver for consumers as it would stifle the natural development of projects and our ability to continue to refine and optimise solutions as things evolve.

It also reduces incentives to use innovative technologies or take additional risk to deliver a higher level of consumer benefit. Examples of this are given below from our experience in RIIO-T1.

Example 1: Burwell MSCs (Scope/Timing Changes)

Earlier in RIIO-T1 there was a project to deploy three MSCs at Burwell (NOA Code BMMS) in 2023 as there was a requirement for a significant amount of reactive support at Burwell substation. By considering how we optimise the solution and the timing of the delivery it was clear that the first two MSCs could be delivered earlier due to being sufficient space to accommodate them without a significant challenge. The deployment of the third MSC was more challenging than the first two and we therefore took the decision to split this into two smaller projects, with an earlier delivery for the first two MSCs to provide some earlier benefit. If the PCD is too restrictive in terms of scope / timing of delivery, there would be no incentive to deliver elements earlier that deliver consumer benefit.

Example 2: Power Flow Control Devices (Innovative Technology)

During the RIIO-T1 period we have worked with the market to progress the development of Power Flow Control (i.e. SmartWires) for use at transmission voltages for the first time anywhere in the world. This technology had the potential to provide additional network capability at a lower cost than some traditional network reinforcement options by re-directing power flows to better balance the network and optimise the use of existing assets but, given its innovative nature, came at a greater risk of failure than more traditional solutions.

By introducing this solution for some of the northern system boundaries (with five deployments in 2020/21) we have mitigated the need for more expensive, longer lead time investments. There were three projects that have been stopped/delayed as a result of these deployments:

- Lister Drive QB Deployment (LDQB)
- Lackenby – Norton Reconductoring (LNRE)
- Mersey Ring Uprating (MRUP)

For example, the Lister Drive QB was taken to the end of our 4.3 NDP TP500 development phase when the Power Flow Control solution become known in the current format. Despite detailed development work having taken place, the RIIO-T1 mechanism enabled and incentivised us to take risks to find an even better solution that provided more overall value for consumers in terms of lower costs and faster constraint cost reductions. The availability and viability of this new technology could not have been known when the project commenced and a prescriptive PCD coupled with an ex-post true-up of allowances would have discouraged us from delivering anything other than what is set out in the PCD.

Example 3: South Coast Reinforcement (Optimising solutions to meet evolving network needs)

Prior to NOA 2019/20, the initial option that was proposed for the South Coast Reinforcement was a new circa 70km circuit from Sellindge to the Longfield Tee. As the project has progressed, and multiple iterations of the FES have been developed, the drivers around the South East and East Anglia regions have evolved. This has shown the need for greater reinforcement in East Anglia, through London and along the South Coast to support the connection of offshore wind generation on the east coast, and the additional interconnection capacity being developed on the east and south east coasts.

In undertaking the Strategic Optioneering work for the South Coast project, we identified an opportunity to develop an optimised solution which provided capacity across eastern and south coast boundaries to support generation and interconnection capacity growth. We have determined an offshore HVDC link between Suffolk and Kent is the optimal solution as part of the broader requirement to reinforce the region. This was supported by the NOA publication in January 2020, which determined this to be the preferred option when compared to other alternatives proposed (including the previous Sellindge – Longfield Tee).

By having a process which is sufficiently flexible to continually optimise solutions across and between regions, we have a better overall solution for consumers and the network. If we had to progress the scope of the investment initially proposed then it may be the case that two separate solutions would be developed to meet the separate requirements, rather than optimising between both. (Whilst this project is part of the SWW/LOTI process, it does demonstrate the need to continually evolve solutions to meet evolving system needs).

iii. Large Onshore Transmission Investment (LOTI) – pre-construction

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
iii.	LOTI pre-construction	Wider Works	152.5	152.5	-89.0		308.6	372.1
	Total:		152.5	152.5	-89.0	0.0	308.6	372.1

We recommend the following errors, issues and new information are considered in updating allowances for LOTI pre-construction:

(a) Factual errors across the draft determination

The Draft Determination states that allowances have been removed for OENO and SCN1 schemes and a baseline of £[redacted] (including indirects) is proposed to allow pre-construction of E2DC and E4D3. However, this value does not reflect the allowances of £[redacted] (excluding indirects) the DD has proposed in the underlying numbers, or the

£[redacted] (£[redacted]m excluding indirects) required to allow pre-construction of E2DC and E4D3. We propose Ofgem update allowances to correct the above errors, which reduces allowances by £[redacted] (£[redacted]m - £[redacted]m).

(b) Methodological errors in unit cost benchmarking and project cost assessment process

No methodological errors were found for this cost category.

(c) New information about ESO and customer requirements

Ofgem have updated baseline allowances for LOTI pre-construction by removing allowances associated with projects not signalled as proceed in the latest NOA publication but have not updated the baseline allowances to add pre-construction funding for new boundary projects. Seven new LOTI projects >£100m were recommended to PROCEED, and pre-construction funding for these was not included.

An updated summary of pre-construction funding needs for LOTI projects >£100m is detailed below. Further details of investment drivers, scope and breakdown of activities can be found in Investment Decision Pack Supplement to NGET_A7.06 Facilitate Competition (Pre-consents) submitted in August 2020.

Project Name	NOA code	EISD	NOA 18/19 Signal	NOA 19/20 Signal	T2 Pre-Construction (including indirects)	
					December	NOA
Eastern Link 1	E2DC	2027	PROCEED	PROCEED	[redacted]	[redacted]
Eastern Link 2	E4D3	2029	PROCEED	PROCEED		
Central Yorkshire Reinforcement	OENO		PROCEED	STOP		
South Coast	SCN1		PROCEED	STOP	[redacted]	[redacted]
New Circuit from Creyke Beck to South Humber	CGNC	2031	N/A	PROCEED	[redacted]	[redacted]
HVDC from Peterhead to South Humber region	E4L5	2031	N/A	PROCEED	[redacted]	[redacted]
South Humber to South Lincolnshire circuit	GWNC	2031	N/A	PROCEED	[redacted]	[redacted]
Tilbury to Grain and Tilbury to Kingsnorth	TKRE	2026	STOP	PROCEED	[redacted]	[redacted]
New circuit from Torness to Lackenby	TLNO	2036	DO NOT START	PROCEED	[redacted]	[redacted]
Central Yorkshire Reinforcement	OPN2	2028	N/A	PROCEED	[redacted]	[redacted]
South Coast Reinforcement	SCD1	2029	N/A	PROCEED	[redacted]	[redacted]
Totals					**£181.5m**	**£443.0m**

We agree with Ofgem's intended reduction in funding requested in our December plan from £181.5m to £[redacted] to partially reflect the latest NOA but recommend a corresponding increase of [redacted] [redacted] excluding indirects) from this adjusted level to reflect the seven additional projects signalled by NOA. This results in an updated pre-consents funding request of £[redacted] for nine LOTI projects over T2.

We note that there may also be benefit in including pre-construction funding for projects greater than £100m that have been triggered by customer driven projects since the submission was made, such as the need for a new 60km route from [redacted]

[redacted] to accommodate offshore wind off the east coast with an imminent need to begin preconstruction.

We recommend that Ofgem update baseline allowances for boundary capability to reflect all changes resulting from the latest NOA publication and customer connections.

(d) Clarity on how baseline allowances interact with the broader framework

The introduction of ex-post assessments will undermine the driver for efficiency and innovation and the resulting allowance uncertainty will delay projects to the detriment of consumers. Please refer to ETQ11 and ETQ12 that details our concerns.

iv. Easements

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
iv.	**Easements**	Wider Works	78.3	78.3	-12.5		12.5	78.3
	Total:		**78.3**	**78.3**	**-12.5**	**0.0**	**12.5**	**78.3**

(a) Factual errors across the draft determination

In Table 17 'Additional LRE schemes' of the NGET Annex (page 48), the Draft Determination references a removal of £14.9m (£12.5m excluding indirect costs) from baseline allowances and stated that no justification had been provided for why the run rate in T2 will be more than the T1 period. However, in the NGET LRE DD spreadsheet provided the £14.9m has not been removed.

(b) Methodological errors in unit cost benchmarking and project cost assessment process

It is noted that the assessment undertaken by Atkins RIIO-T2 Engineering Submission Review Summary Annex accepts the IDP need case which is clear and unambiguous due to the continued need to secure permanent rights to maintain our assets.

Assuming the £14.9m has been removed, we **do not** agree with Ofgem's proposed allowance for securing easements and we provide additional rationale for the increase in run rate for the T2 period, below.

Average house price, UK, January 2005 to January 2020

Source: HM Land Registry, Registers of Scotland, Land and Property Services Norther Ireland, Office for National Statistics – UK House Price Index

Property prices and historic easement claims and accruals provide strong evidence for the need for increased allowances in the T2 period.

Firstly, there is a chronic housing shortage which is accepted by the government with "Planning for the Future" white paper released August 2020 for consultation. It is acknowledged that external events such as the financial crisis of 2007/08 has an impact on house prices, but this is in the short term with the ONS reporting general upward trend throughout the decades. Below demonstrates the house price recovery from 2007/08, then continue climb year on year thereafter.

Savills reported in their Q2 2020 Prime Regional Residential report that they forecast a 2% drop in average prices in the second hand market in 2020, but then a 5% growth in 2021, 6% increase in 2022, 3.5% increase in 2023 and a 2.5% increase in 2024 resulting in an overall 5year compound growth of 15.7%

[redacted]

It was reported by Avison Young in March 2019 that the demand for "big sheds or distribution warehouses" increased by 28% compared to the previous five-year average. Since that report, Covid-19 has reportedly accelerated the transition to online shopping by 3 years compared to previous predictions further fuelling the demand for big sheds. We have initial discussions with two potential claimants this financial year with the expectation they will be received in T2. Savills further comment *"Our latest client survey, which was conducted just prior to the SDLT change, provides further insight. Results showed that the experience of Covid-19 had caused almost three quarters of respondents to reconsider their work-life balance. This, in turn, has made prospective buyers increasingly more committed to moving in the next 12 months, with the net balance growing from +9% to +32% since late April 2020".*

The underlying economic principle of supply and demand suggests that, with a housing shortage and strong demand, as well as industrial development claim numbers coupled with price growth will result in an increased easement spend in T2.

Through our thorough audit process, we annually review all claims and release accruals where claims have been successfully defended. Since August 2019, we tracked monthly variance on total claim numbers and total accruals held which is shown below.

[redacted]

[redacted]

[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	
[redacted]		[redacted]		[redacted]		[redacted]	

We recommend that Ofgem update baseline allowances to reflect the full allowance requested in our December baseline submission.

(c) New information about ESO and customer requirements

We have found no new information for this cost category.

(d) Clarity on how baseline allowances interact with the broader framework

No points of clarity are sought for this cost category.

v. Reactors

£m (18/19 prices)

NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
v.	Reactors	Wider Works	25.8	25.2	-4.6	5.2		25.8
	Total:		25.8	25.2	-4.6	5.2	0.0	25.8

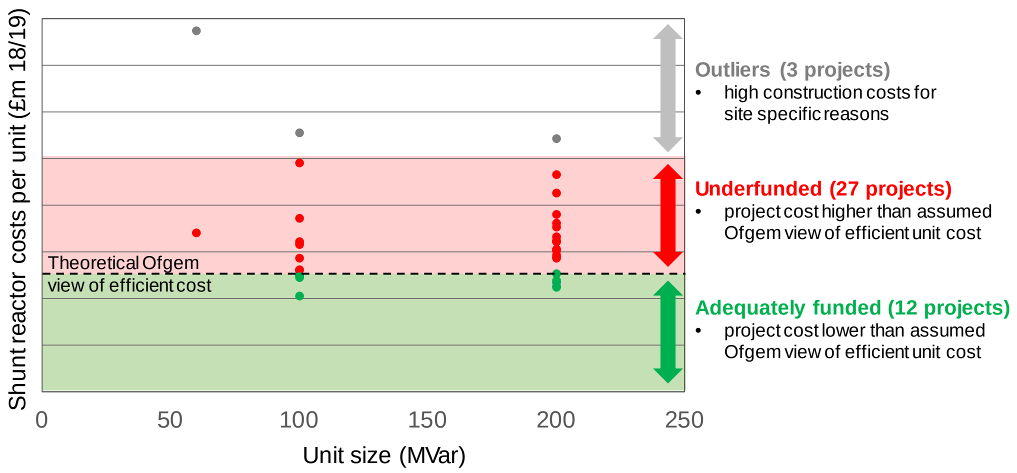
(a) Factual errors across the draft determination

In Table 11 of the NGET Annex (p.22) 'NGET bespoke PCD proposal' the Draft Determination references the removal of £4.6m (£5.5m including indirect costs) of allowances for shunt reactors from the baseline as a result of the cost assessment exercise. However, in the underlying NGET LRE DD spreadsheet used for the Draft Determination provided by Ofgem the £4.6m has not been removed.

(b) Methodological errors in unit cost benchmarking and project cost assessment process

If this £4.6m has been removed, we do not believe that the process has effectively assessed the efficient cost of delivering shunt reactive compensation for reactors of different sizes and at sites with varying conditions. Our analysis of input data provided to Ofgem as part of the unit cost allowance calculation for our volume driver proposal, shown in the chart below, concludes that approximately 70% of these reactors would be underfunded if £4.6m was removed evenly across the [redacted] reactors in our baseline plan.

Assumed shunt reactor project cost leaves ~70% of projects underfunded



The impact on ESO network operating costs of not having appropriate levels of reactive compensation in place can run into the 10s of £millions per annum. Not adequately funding these investments would therefore be detrimental to consumers.

Ofgem have also arrived at a single unit cost per asset class and voltage, this is overly simplifying the unit cost categorisation and incorrectly disallowing efficiently incurred costs of £0.5m for this category. The dataset shows multiple peaks associated with the installation of additional circuit breakers in existing bays at the lower end of the cost envelope against the installation of a new circuit breaker and all associated ancillary equipment at a new substation, with a far greater associated unit cost. These are not comparable units but have been combined a single average cost.

We recommend that Ofgem re-instate our proposed allowance for these schemes where they agree the need case has been justified.

(c) New information about ESO and customer requirements

We have found no new information for this cost category.

(d) Clarity on how baseline allowances interact with the broader framework

Any NGET additional reactor investments recommended by the ESO through whole system assessments should be funded through the volume driver uncertainty mechanism for reactors proposed by Ofgem. The Draft Determination states that further work is required to identify an appropriate Unit Cost Allowance for reactors. While we provided extensive evidence of historical and forecast costs in our December submission that were used to develop our proposed UCAs, we would welcome the opportunity to work with Ofgem to understand their concerns and ensure a sufficiently flexible uncertainty mechanism is put in place. Please see our details response to reactor UM in ETQ13C.

The low baseline allowances requested in our business plan submission reflect the fact that alternative, whole system options can play a large role in reactive compensation provision. We are seeking to facilitate the emerging whole system processes (e.g. the ESO pathfinders) by using a volume driver to fund transmission investments only after they have been identified as providing best value for consumers through these whole system assessments.

vi. Site Separation

£m (18/19 prices)								
	NGET plan category	Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
vi.	**Site separation**	Wider Works	34.8	34.8				34.8
	Total:		**34.8**	**34.8**	**0.0**	**0.0**	**0.0**	**34.8**

We agree with Draft Determination's proposed allowances for site separation and have found no (a) factual errors, (b) methodological errors in unit cost benchmarking and project assessment or (c) new information on ESO and customer requirements.

(d) <u>Clarity on how baseline allowances interact with the broader framework</u>

The Draft Determination indicates a PCD could be a suitable approach for this cost category. We would welcome the opportunity to work with Ofgem to further develop and agree a PCD that provides certainty around delivery of an output for consumers and allows the flexibility to optimise the delivery plan as things change. We do not believe that PCDs with secondary deliverables are required to achieve this aim.

Our response to NGETQ5 that details our concerns and remedies for PCDs.

vii. Protection and Control

£m (18/19 prices)								
	NGET plan category	Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
vii.	**Protection and control**	TSS Infrastructure	26.1	26.1	-22.2		5.0	8.9
	Total:		**26.1**	**26.1**	**-22.2**	**0.0**	**5.0**	**8.9**

(a) <u>Factual errors across the draft determination</u>

In Table 17 of the NGET Annex (p.48) 'Additional LRE schemes' the Drat Determination indicates that an adjustment of £26.43m has been made, however we do not believe this has been reflected in the Draft Determination proposed allowances of £891m.

(b) <u>Methodological errors in unit cost benchmarking and project cost assessment process</u>

We have found no methodological errors for this cost category.

(c) <u>New information about ESO and customer requirements</u>

The <u>ESO Operability Strategy Report 2019</u> section 6 on stability sets how fault levels are becoming an issue that require action at different rates for different regions. For some regions in England and Wales, such as the southwest, we anticipate the requirement to adjust settings on protection and control devices to ensure continued effective operation across all times of year is needed in the T2 period. This requirement is due to an aggregated drop in fault levels across these regions due to more transmission and distribution connection renewable generation and so is not triggered by traditional load-related investment triggers, such as customer connections.

We recommend that Ofgem re-instate £5m of our proposed allowance for changing protection settings so that there is no gap in funding to do this work before the MSIP re-opener can be triggered.

(d) <u>Clarity on how baseline allowances interact with the broader framework</u>

We understand from Table 17 in the NGET Annex, that the MSIP re-opener can be used to request funding once the studies have been completed (we note that this 'externally driven' requirement is currently missing from the list of eligible reopeners – see response to ETQ13). We believe a provisional allowance of £5m should still be included the baseline to avoid any delays in investment and potential impacts to the network.

viii. System Monitoring

£m (18/19 prices)									
NGET plan category		Ofgem cost category	NGET submission (net indirect)	Ofgem published DD allowances	a. Factual errors	b. Methodology errors	c. New information	NGET proposed FD allowances
viii.	System monitoring	TSS Infrastructure	38.9	38.9				38.9
	Total:		38.9	38.9	0.0	0.0	0.0	38.9

We agree with Draft Determination's proposed allowances for site separation and have found no (a) factual errors, (b) methodological errors in unit cost benchmarking and project assessment or (c) new information on ESO and customer requirements.

(d) <u>Clarity on how baseline allowances interact with the broader framework</u>

The Draft Determination indicates a PCD could be a suitable approach for this cost category. We would welcome the opportunity to work with Ofgem to further develop and agree a PCD that provides certainty around delivery of an output for consumers and allows the flexibility to optimise the delivery plan as things change. We do not believe that PCDs with secondary deliverables are required to achieve this aim and suggest that the output is defined as the volume ([redacted]) of substations that will be upgraded to provide PMU capability by end of T2. This approach would also tie in with the STC-P 27-1 requirement to have coverage at all substations by the end of T2.

Our response to NGETQ5 that details our concerns and remedies for PCDs.

NGETQ12 Do you agree with our proposed allowances in relation to non-load related capex? If not, please outline why.

We do not agree with your proposed allowances in relation to non-load related capex. The proposed allowances for asset health, at less than 30% of historic investment levels, do not safeguard the reliability of the network and completely disregard the considered views of stakeholders. The negative consequences of such unprecedented cuts in asset health investment will be significant and felt for many years to come if not rectified in Final Determinations.

Ofgem proposed a non-load related expenditures (NLRE) allowance of £643m. This is in contrast to the proposed NLRE allowance in our business plan of £3,347m for T2. We have calculated that Ofgem's proposed allowance increases the level of risk on our network by 24% over the next five years. We therefore consider that these allowances are inadequate even to meet our minimum legal requirements in respect of network performance. Consumers would face a heightened risk from deteriorating network reliability, which would also impede progress towards net zero in both the near and longer-term as already constrained system access would be used by catching up on reliability, rather than connecting renewable generation or installing lower emissions assets.

We now understand that Ofgem wanted more detailed asset by asset information, which they have been provided in our supplementary evidence provision (118 documents and new BPDTs). We are working constructively with Ofgem to ensure we deliver the shared objective of a reliable network. Our comments in this response relate to draft determination documents, as we need to respond to the published determination, and ensure that we continue on the current path to a final determination which gives the level of funding required for network reliability.

Falling reliability of the assets comprising circuits will reduce the availability of circuit capacity for operational use due to either immediate unplanned outages to repair critical failures or due to the need for rating restrictions to ensure safety until repairs can be scheduled. This reduced availability of circuit capacity will increase constraint costs in both the T2 and T3 periods significantly compared to the situation sought in our RIIO-2 plan where component reliability is maintained and asset renewals take place in outages planned to minimise constraints. The average cost of constraints due to the reduced availability of circuit capacity at a time of increasing wind connections and wind output is expected to exceed the cost savings from reduced volumes of asset health activity proposed in the Draft Determination, which could increase consumer bills by up to £1.80 per year.

The allowances in DD would impact asset and site level reliability, increasing the potential to ultimately impact the reliability experienced by consumers and directly connected customers. We would expect 20 more asset failures in T2 if allowances were kept at DD level compared to our submitted plan. This will also be a blocker to achieving net zero in the longer-term due to already constrained system access being used to catch up on asset replacement. We have set out our headlines below, the reasons why your draft determination is not stakeholder-led, how we have followed your guidance at every step, and a detailed category by category assessment of your proposed allowances.

Your draft determination:

1. **Jeopardises network reliability** – Cutting investment in asset health by 70% compared to historic levels, and by 80% compared to our submitted business plan cannot possibly result in stable performance in terms of reliability or asset risk. The consequences of this reduction will be far reaching and felt in both the short and medium term with a real possibility that it cannot be corrected in the long term.

   Under investment will manifest as a reduction in asset, route and site level reliability within a couple of years. We have calculated that the risk of a failure on our OHL conductors would double by 2026, and a failure of fittings increase by 16%. Inherent redundancy and designed resilience in the network mean individual failures will not automatically lead to a supply interruption, however, the potential to ultimately impact the reliability experienced by consumers and directly connected customers is materially increased, particularly in extreme weather events when multiple co-incident failures can occur.

2. **Is not stakeholder led** – In the extensive stakeholder and consumer engagement we carried out on our business plan, reliability was consistently the top priority, with stakeholders wanting to retain current levels of reliability in T2 and beyond. Stakeholders & consumers told us that they were willing to pay

more for increased reliability, as this allowed for more optionality in the future for net zero.

The populous draft determination survey carried out in August 2020 highlighted that the public prioritises investment in energy services over cutting spending to reduce energy bills. One of the top two priorities is "investing now to ensure Britain's energy network is reliable and significantly reduce the risk of power cuts". This remains one of the top two priorities regardless of financial position; even those who are struggling financially think that investing in energy resilience and reliability are more important than other priorities, including cutting spending to reduce bills.

Escalating risk levels on the network are at odds with stakeholder requirements and may not be recoverable in the longer term. Our proposed Business Plan aimed to hold risk levels stable on the network, by contrast, the proposed levels of investment in Draft Determinations allow risk to increase by at least 24% over the five-year period based on volume disallowances only. Whilst the majority of this risk relates to network reliability, we also manage significant safety and environmental risks. We always apply additional risk mitigation where asset intervention is not possible, such as Risk Management Hazard Zones, however, this is no substitution for risk based preventative intervention. Permitting cumulative safety risk to escalate over time, as would inevitably happen under the proposed volumes, is inconsistent with the ALARP (As Low as Reasonably Practicable) principles set out by the HSE (Health and Safety Executive).

3. **Does not adequately protect consumers** – Ofgem have a role to 'protect the interests of existing and future consumers', two of those interests being;
   - ☐ The reduction of electricity-supply emissions of targeted greenhouse gases; and
   - ☐ The security of supply to them

Ofgem has cut allowances in all areas of reliability, which have a compound effect on consumers:

- ☐ **reducing preventative maintenance by 74%**;
- ☐ reducing the work we do to replace the critical overhead lines that interconnect the entire system by 80%, consequently **increasing the probability of failure from 12.6% to 27%**; and
- ☐ reducing the replacement of protection & control systems which keep supplies safe and secure following a failure by 87%.
- ☐ increases costs to consumers; cuts to reliability amount to a saving of £1.20 per year, but the overall impact of these cuts **could lead to consumer bill increases of £0.60 per year in T2 and up to £1.80 per year in T3.**

A radical change to asset health investment practices, as proposed in Draft Determinations, undermines the basis on which all other network development and investment decisions are made. Both NOA (Network Options Appraisal) and SQSS (Security and Quality of Supply Standard) rely on an inherent assumption that historic performance levels prevail. This assumption cannot be made if investment levels are materially reduced, resulting in the network carrying higher levels of risk and a population of assets that is on the whole more aged and degraded than in previous periods. We have studied a typical storm scenario in 2026 and concluded that the threat of coincident asset failures would take the network beyond planning and operating standards.

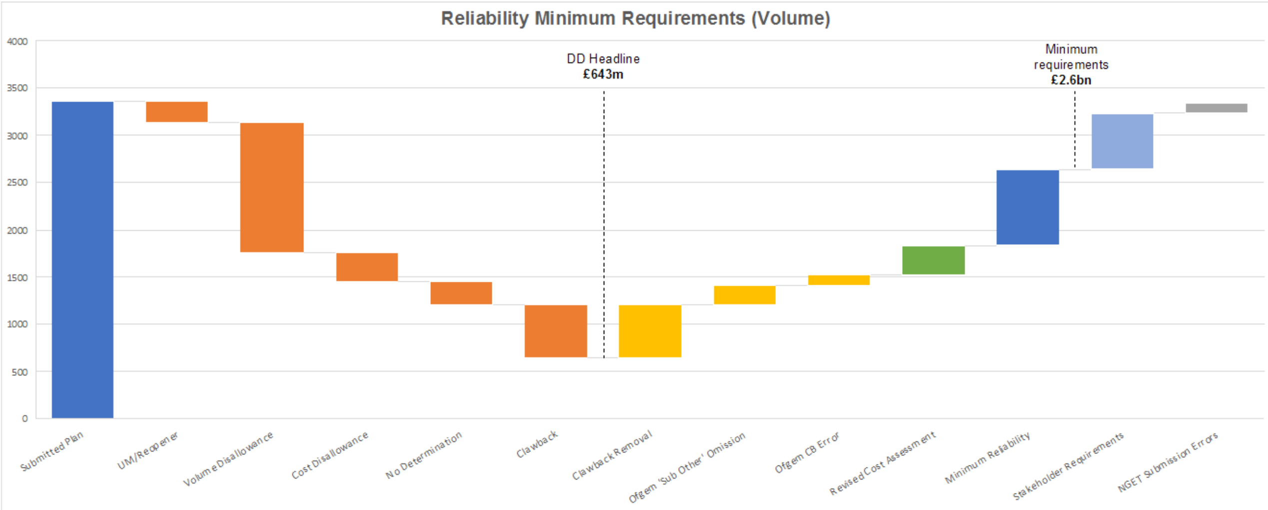
4. **Has multiple errors** – Ofgem have not used all the detail provided in the formal submission, SQs and BPDTs which has resulted in incorrect proposed allowances being published, some missing categories (e.g. circuit breakers), an incorrect output target, and flawed cost assessment in some areas, e.g. an incomplete cost assessment of P&C results in a 76% reduction in allowance in this area. We recognise that many of these areas have been acknowledged, and with further evidence already submitted by NGET, both parties are confident that many of these are now resolved.

5. **Is inconsistent between companies.** Your approach to cost assessment for NGET's NLRE was not consistent with that applied to other TOs and has resulted in unjustified cost reductions that leave NGET with interventions in certain asset categories that cannot be delivered for the stated allowances. (e.g. the 76% unit cost reduction applied to our allowed P&C volumes is not credible).

6. **Provides feedback not consistent with BP Guidance** – your draft determination is not reflective of the guidance set out by Ofgem, or the guidance provided through extensive bilateral engagement and working groups, but assessed against a set of criteria unknown to networks. It appears that Ofgem have carried out a BPI stage 3 assessment against the stage 1 criteria, incorrectly resulting in a stage 1 penalty for NGET. Since the first feedback we received from Ofgem on our business plan in January 2020, we have been aware of the greater level of detail required by Ofgem to determine the allowances we need to address network reliability. This is over and above Ofgem published business plan guidance. We have addressed each and every piece of feedback, and provided an additional 118 supplementary evidence reports covering every area of network reliability. Ofgem has stated that it now has sufficient evidence to increase allowances in most areas, although there are still some areas which Ofgem need more detail on before approving proposed allowances.

7. **May prevent the future transition to net-zero**. Our ability to recover the resulting risk position in RIIO-T3 will be constrained by system access. We analysed the impact of carrying-over work into T3 and determined that in the most constrained region there would be c.50% more outage days required than the system can accommodate. Additionally, at the replacement rate proposed for overhead line conductors it would take over 100 years to refresh a network that was largely built in in the 1960s/70s with an anticipated life of 50 to 60 years. Thus, the impact of these investment levels will be felt for many regulatory periods to come. Of notable concern to our stakeholders and customers is the potential for this to detract from NetZero ambitions and in particular connecting offshore wind.

The correction of errors already acknowledged by Ofgem, addressing of further problems in cost assessment, and the provision of detailed supplementary evidence justifies the increase in reliability allowances of a **further £1.95bn** in addition to the £643m Ofgem proposed in its DD. This provides the minimum acceptable level of expenditure for reliability to prevent short-term reliability issues. Additional investment is required on top of this to prevent fundamental changes to the transmission network, namely delivering the levels of reliability requested by stakeholders and consumers and preventing the knock-on effect to net zero.



The waterfall graph starts with our formal business plan submission on the left (£3.35bn being our Capex proposal for Reliability, minus the Information Technology costs of £176m) and in orange identifies the reductions that Ofgem have undertaken to reduce our RIIO2 investment to £643m (Table 28 in DD minus the non-reliability costs for Black Start, Easements and SCADA). The yellow bars represent errors, and the green bar represents the computational errors in cost assessment.

The dark blue bar indicates the minimum acceptable level of investment needed for reliability.

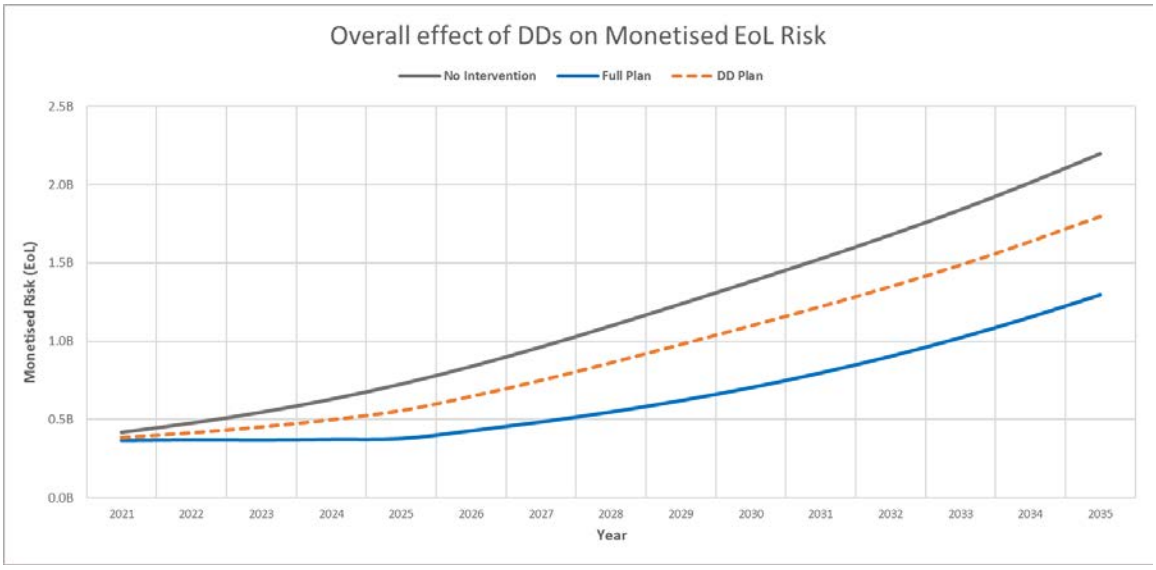
The lighter blue bar indicates the additional level of investment needed to meet the needs of stakeholders and consumers, to ensure reliability remains at current levels, and retain optionality to deliver net zero in the future.

We have also sought an independent expert engineering review of this supplementary evidence. The review confirms that the allowances provided in DD are a quarter of the appropriate level for the categories with the greatest disallowance (P&C, Bays, OHLs & SGTs). We do however welcome the collaborative approach provided by the Ofgem Engineering team, and the recent feedback from Ofgem which recognises the supplementary evidence being provided more closely meets their requirements.

DD is not Stakeholder led, and does not deliver what stakeholders, consumers and customers have asked for

We carried out our most extensive stakeholder engagement programme to date for RIIO-2, asking what stakeholders and consumers wanted at every stage of our business plan development. Our formal submission in December 2019 reflects exactly what stakeholders and consumers have informed us. Ofgem have ignored what stakeholders want, instead deciding to promote a headline bill reduction, even where this has a negative effect on reliability and optionality for net zero.

- Stakeholders told us that they wanted a **Flat Risk Profile.** They informed us that they supported retaining current levels of reliability, and that this was their number 1 priority, as we become more reliant on electricity for transport and heat. At the very least, reliability should be no worse than current levels.



The graph above shows there will be a 24% increase in network risk at the end of RIIO2.

The grey line shows the increase in network risk without intervention, the blue line shows the network risk that stakeholders have requested (which our submitted business plan delivers), and the dotted orange line shows the impact of Ofgem's draft determination. Note, these risk increases only take into account RIIO2 interventions. Work in T3 and beyond serves to maintain a flatter risk profile.

- ☐ Stakeholders were **willing to pay for more reliability**. We offered consumers the option to have lower bills, but hold more network risk, or higher bills with increased reliability. Consumers were clear that they were willing to pay for more reliability, but were not willing to accept lower levels of reliability, even if this meant lower bills.
- ☐ We **offered Stakeholders lower spend in some areas, they said no**. In the many workshops we carried out to engage stakeholders whilst developing our business plan, we offered real options for lower spend in each key asset category (e.g. P&C, Circuit Breakers). In each case stakeholders were clear that ageing, poor health, and obsolete assets should be removed from our network as soon as possible.
- ☐ **Ofgem have not allowed customer driven projects.** Ofgem have re-iterated a previous error that the **Tyne crossing** re-opener had been mutually agreed, this is not true - timing is crucial hence this project needs to be in the baseline to enable us to start development work on this project immediately. The Tyne crossing works are not essential to reliability, but of huge importance to the local stakeholders and the strategic objective of the North East and their role in the green transition. Therefore we believe it is in the interests of the region and wider national agenda to include in the baseline.

  Dinorwig power station provides critical balancing services to the ESO, ensuring a fast response from faults, and keeping the frequency stable at 50Hz. The cables that connect this power station to the network are in very poor health as detailed in our evidence, requiring many outages per year to repair faults at a risk of [redacted] to the consumer in constraint costs. This is further evidenced by need cases from the Electricity System Operator and customer. The ESO are particularly concerned, stating:

[redacted]

Ofgem have made further errors in their draft determination, stating that we had not considered this project for competition. This is wrong, our consideration was on page 106 of our formal submission. Ofgem have also incorrectly proposed LOTI for this project, having previously informed that this was only for load-related projects. This project is in our minimum requirement for reliability and must be included in baseline funding. NGET has already incurred significant spend on this project and physical works have already commenced.

Geographical Consequences

Ofgem have conducted an asset by asset assessment of investment which ignores cumulative risks when assessed as a whole network. This has resulted in some geographical areas of the network having a higher likelihood of failure of assets than others, with the greatest numbers in London. In some cases, assets have predicted failure rates of 60% chance of failure or higher in any given year in T2. In addition, a number of critical north-south circuits have a higher likelihood of failure with the proposed DD allowances compared to our business plan submission. This is particularly prevalent on the South Coast, where there is an increased likelihood of failure on circuits where key connections are expected in coming years.

The impact of our business plan submission can be seen in the diagram below. The colour coding refers to the residual likelihood of failure should our proposed T2 business plan submission be delivered. Red showing areas of the highest risk.

[redacted]

The following diagram shows the impact should Ofgem's DD plan be delivered.

[redacted]

Cost Assessment & BPDT

Ofgem claims that our portfolio approach in compiling BPDT for NLRE prevented the level of cost information analysis that was undertaken by Ofgem for other TOs. We were surprised to see this raised, as this issue has been addressed with Ofgem in working meetings before, and there was no specific feedback provided by Ofgem following our draft submissions in July and October. Given the scale of NGET's asset base relative to the other TOs, a granular, asset-by-asset appraisal would be wholly disproportionate for both NGET and Ofgem. It would require a monitoring effort that would be very costly to run and would deliver no benefits over the current portfolio approach that relies on a wealth of relevant data (obtained through condition monitoring, forensic analysis of assets removed from the system, external supplier and manufacturer information, and many decades of operational data) to predict the degradation or expected age of asset families and similar groups of assets. Our approach has proven itself to be efficient over time, whereas imposing a requirement on us to work at the level of the individual asset would, simply put, increase cost and worsen outcomes for consumers.

Following bilateral discussions with Ofgem, the BPDT has been recut in greater detail to prevent further issues in FD. Detail can be found within the individual asset category descriptions.

Working Towards Final Determinations

We have welcomed the opportunity of continued engagement with Ofgem in order to reach our shared objective of safeguarding network reliability. As a result of feedback received, we have submitted an additional 118 supplementary evidence reports and new BPDT (Business Plan Data Tables). For each asset category we have outlined our asset management strategy and key considerations when preparing the business plan in line with stakeholders' requirements and deploying mutually agreed methodologies such as monetised risk. These over-arching reports are supported by numerous annexes which set out at an extremely granular level the need case for investments, the asset evidence used as well as all available engineering and development considerations. The re-submitted BPDT ensures direct line of sight from the investment details described to the data table entries.

In order to distinguish between the minimum investment required to maintain reliability (in the short and longer term) and investment which offers total risk stability (in line with stakeholders' expectations and our considered asset management strategy) we have conducted an internal review of our investments and categorised them in this way in our supplementary evidence reports. We have done this to ensure there is no ambiguity about the minimum acceptable level of investment required to safeguard our common goal of securing network reliability. We maintain, however, that there are significant additional benefits that our stakeholders prioritised which will be foregone at these levels with consequential detriment to consumers, customers and the nations' NetZero ambitions.

We understand, from recent engagement at all levels, that this distinction and clarity is helpful for your analysis and that the supplementary evidence provided is of sufficient detail and quality for you to revisit the volumes allowed in draft determinations and specifically that meaningful and substantial additional information and data has been provided in line with your requests.

To ensure sufficient internal challenge of our position on minimum investment for reliability, we engaged DNV GL to provide an independent, high-level view on the potential consequences of failing to invest in reliability, as well as to provide an independent estimate of the minimum required spend for NGET in RIIO-T2 to maintain the current level of network reliability. In forming their views DNV GL concentrated on four critical asset classes which make up £1.77bn of the funding request and the associated disallowance. They have drawn on DNV GL's 90+ years as a global expert advisor to transmission network owners and operators and deep knowledge of asset management in transmission systems and other complex high value infrastructure. The study reached the conclusion that "Ofgem's proposed cut of NGET's £1.77bn funding request to £324m falls significantly short of what we believe to be the minimum required spend for these asset groups, which we place at £1.27bn."

T1/T2 Clawback

The ex-post re-opening and clawback of settled T1 allowances where no mechanism or vires exists, undermines the 'stable and predictable' RIIO regulatory regime.

What Ofgem has Proposed

In the NGET Annex, firstly in a footnote, Ofgem has announced a new proposal to reduce the ET1 allowance for non-load related expenditure (**NLRE**) by undertaking *"a £556m clawback of unspent non-load allowances for T1/T2 crossover work"*.[1]

Ofgem's exceptionally brief and unevidenced explanation for this significant and unexpected proposed reduction in NGET's NLRE allowances for the RIIO-ET2 period is that:[2]
As part of RIIO-ET1 baseline allowance, there is a provision of £1069m to fund NLRE work that needed to start in in RIIO-ET1 and would be completed in RIIO-ET2;
Ofgem has now divided this amount into two parts – the first part (up to and including 31 March 2021) will be funded in RIIO-ET1 "*subject to true-up*", and the second part (from 1 April 2021 to 31 March 2026) will be part of the total RIIO-ET2 baseline allowance for NLRE; and

- ☐ Ofgem believes that, given the amount funded in RIIO-ET1 "is already certain", it is entitled to carry out a "*true-up*" and reflect that in the setting of RIIO-ET2.

Why we are concerned

Ofgem is mistaken in its assumption that it is entitled to 'clawback' any of the RIIO-ET1 NLRE baseline allowance. NGET's position is that <u>there is no valid basis for this proposed NLRE clawback,</u> either in the existing electricity transmission licence, RIIO-ET1 Final Proposals, or any subsequent regulatory determination or guidance. Ofgem does not explain or evidence where in the RIIO-ET1 arrangements this "true-up" mechanism was put in place, or even envisaged.

In fact, Ofgem's proposal is contrary to the stated position in RIIO-ET1 documentation regarding the treatment of licensee under or overspend of allowances. The RIIO-ET1 framework makes it clear that the NLRE baseline

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[1] Ofgem, Draft Determination, NGET Annex, footnote 38 on page 39 linked to Table 14: Proposed NGET allowance for RIIO-2 period

[2] Ofgem, Draft Determination, NGET Annex, paragraphs 3.65 and 3.66.

allowance was committed and subject to RIIO incentives, and was not to be subject to any uncertainty or other adjustment mechanism. The RIIO-ET1 documents make clear that Ofgem considered while setting the allowance in RIIO-ET1 whether it was appropriate to adopt an uncertainty mechanism, but rejected this on the basis that NGET was best placed to manage the risk. The NLRE baseline allowance was also subject to the relevant sharing factor, which operates so as to ensure that consumers benefit through the sharing of any outperformance achieved. It is not now open to Ofgem to revisit this decision to subject the allowance to a true-up mechanism at the outset of RIIO-ET2.

Ofgem's proposal is also contrary to the principles of the RIIO model and its framework of incentives and outputs. The implications of Ofgem's proposal have not been fully considered, but NGET's initial view is that the proposal risks significantly undermining the incentive effects of the

RIIO framework and drives the wrong incentives for network companies.
The manner in which the proposed ex-post adjustment has been introduced (without any consultation, engagement with the licensee or supporting evidence and rationale) is clearly contrary to best regulatory practice and undermines certainty and transparency. Such action diminishes investor confidence, which will ultimately increase long-term costs for consumers.

Given the material and unanticipated impact of the proposal, NGET requests that this proposed clawback is removed prior to Final Determination. As set out above, there is no basis for Ofgem to bring forward the proposal.

Our evidencing of these points is set out below:

The NLRE ET1 baseline allowance is only subject to a true up in limited circumstances, which do not apply here

The Draft Determination does not set out the regulatory basis on which Ofgem considers that an ET1-clawback applies to the RIIO-ET2 baseline allowance. That said, the RIIO-ET1 Final Proposals do allow for costs to be excluded from the RIIO-T2 allowance in two limited circumstances:[3]

(a) First, if a TO fails to satisfy the network output measures (**NOMs**), then "*[a]voided costs associated with under delivery are excluded from the RIIO-T2 allowance*".

(b) Second, if the TO under-delivers against the NOMs and it fails to justify the under-delivery as being in the best interest of consumers, then any benefit of the financing cost of the delayed investment could be clawed back.

NGET's regulatory reporting into Ofgem each year has confirmed that the NOMs risk targets are being met at a portfolio level and this has been further confirmed in RRP20.

3 Ofgem, RIIO-T1: Final Proposals for NGET and NGG: Outputs, incentives and innovation Supporting Document, 17 December 2012, paragraphs 2.23 to 2.24 and Table 2.1. Available at: https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/2_riiot1_fp_outputsincentives_dec12.pdf

Delivery of the required NOMs output has been achieved and therefore this mechanism will not adjust allowances.

Outside of these two limited circumstances, the RIIO-ET1 baseline allowance can only be retrospectively adjusted where exceptional or defined circumstances apply. The following extracts of the RIIO-ET1 Handbook make clear that *ex post* adjustments to revenue would be limited to all but the most exceptional circumstances:[4]

> *...we will commit to not making retrospective adjustments to revenue in the event that costs turn out to be different to what was assumed in the price control itself, save through the application of the efficiency incentive rate.* ***We will only consider using such 'ex post adjustments' if outputs are not delivered or if we have a concern that a company has manifestly wasted money.***
>
> *[...]*
>
> *For the upfront efficiency incentives to work as intended, we need to make a firm commitment that the incentive rate set at the price control review will be honoured. We recognise that this will require a commitment not to make discretionary adjustments to the revenues that companies are allowed to collect, based on comparisons between what a company actually spent and the expenditure forecast at the price control review. We will provide this commitment save in the exceptional circumstances outlined in paragraphs 10.21 to 10.25.*[5]
>
> *Provided that a company delivered the outputs agreed at the price control review, it will enjoy the benefit of any under-spend relative to the expenditure assumed in the price control, in line with the specified incentive rate.* ***We will not make discretionary adjustments to 'claw back' differences between the base revenue allowances set at the price control review and what a company actually spent****. Indeed, we will not undertake any detailed assessment of the expenditure level as long as outputs were being delivered.*

Neither the limited exceptions above, nor any of the "exceptional circumstances" envisaged in the RIIO-ET1 documentation, apply in the present case.

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4 Ofgem, RIIO-T1: Handbook for implementing the RIIO model, Chapter 10 – efficiency incentives, References 10.3, 10.18 and 10.19

5 Paragraphs 10.21 to 10.25 address the circumstances in which Ofgem would make adjustments to override the sharing of actual expenditure through the efficiency incentive rate. Ofgem states that a reasonably high hurdle will be required for such an adjustment to be made – Ofgem would "*need to show that expenditure decisions taken by the company* ***were unreasonable at the time they were made****, in light of the information available at that time. We will not use this option to penalise companies that took reasonable decisions to anticipate future customer needs or to experiment with new delivery approaches, even if these turned out to be unsuccessful with the benefit of hindsight*". Clearly, this threshold is not met in the present circumstances.

In the absence of these conditions being met, there is no mechanism for Ofgem in the RIIO-ET1 arrangements or in NGET's transmission licence to "clawback" the RIIO-ET1 NLRE allowances in RIIO-ET2. Ofgem is therefore mistaken in its assumption that the allowances can be subject to a "clawback" or any other form of true-up mechanism.

The NLRE baseline allowance was committed.[6] *This covered all works required in the RIIO-T1 period related to NLRE, including where these works were completed in later price controls. This was not subject to any uncertainty or other adjustment mechanism (despite an initial proposal from NGET to this effect), other than that specified in SLC 2M relating to over- or under- delivery as highlighted above, for the reasons set out in RIIO-ET1 Initial Proposals:*[7]

Due to the uncertainty associated with the forecast of asset degradation and unexpected type faults, the asset renewal volumes forecast by NGET may vary over the RIIO-T1 period. NGET"s forecast on risk is P50 based and we consider that the risk of uncertain renewal volumes is symmetric. ***As an asset owner, NGET is best placed to manage this risk****. Therefore we do not propose any uncertainty mechanism to address the risk associated with uncertain asset renewal volumes.*

> *In its business plan, NGET set out an uncertainty mechanism to fund earlier asset replacement in the event that load-related expenditure projects were delayed during RIIO-T1.*

We do not consider this uncertainty mechanism to be necessary. Whilst we accept that there may be a rationale to advance replacement work, NGET has not justified the need for an uncertainty mechanism. We consider that our proposed total funding package and incentives will allow NGET to do this without the need for an additional uncertainty mechanism. Furthermore, any expenditure above baselines will be subject to the totex efficiency incentive, meaning that the cost effects of moving this expenditure forward will be shared with customers.

This extract sets out Ofgem's clear finding that no uncertainty mechanism or other adjustment mechanism was required in respect of this allowance. This funding was therefore fixed with NGET managing the risk of over or underspend.

It is therefore unacceptable for Ofgem to apply this significant and unexpected ex-post reduction in NGET's NLRE allowance – defeating NGET's expectations of the NLRE RIIO-ET1 allowance as settled and committed – in the absence of any valid regulatory basis for doing so.

Ofgem's decision to apply a <u>clawback of the ET1 NLRE baseline allowance is contrary to RIIO principles and undermines incentives</u>

Ofgem's NLRE clawback proposals are also inconsistent with the principles of RIIO-1 and its framework of incentives and outputs.

The above extracts from RIIO-ET1 documentation confirm that there will be no discretionary adjustments to 'clawback' differences between base revenue allowances set at the price control review and what a company actually spent. This principle

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[6] Ofgem, RIIO-T1: Final Proposals, Cost assessment and uncertainty, paragraph 5.5.

[7] Ofgem, RIIO-T1 NGET Initial Proposals, Cost Assessment and Uncertainty, paragraphs 5.25 to 5.27.

applies to the entirety of the NLRE allowance that was committed in RIIO-ET1, regardless of whether certain NLRE works have since been pushed into RIIO-ET2. As evidenced by the above quotation from Initial Proposals, Ofgem was explicit that, as an asset owner, NGET was best placed to bear the risks of changing delivery timescales (which Ofgem judged to be symmetrical).

Notwithstanding that there is no regulatory basis on which Ofgem can implement the clawback, the implications of Ofgem's proposal have not been fully considered. For instance, if NGET advanced projects from RIIO-ET2 delivery into RIIO-ET1 then Ofgem's approach would not provide any funding for that project, with the additional expenditure adding to the 'clawback' amount. There are further other perverse incentives this creates. Ofgem's approach suggests that the TOs' delivery plan should be static, with TOs only doing what was forecast when the allowance was set, with the potential that optimisation leads to allowances being reduced and the licensee being penalised for doing the right thing in the best interests of end consumers. Had Ofgem suggested this at the time of setting RIIO-T1 allowances and mechanisms then this consequence would have been debated. As explained above, the potential for a true-up was not discussed, consulted upon, or even alluded to prior to the Draft Determination for RIIO2.

Given that this adjustment was not envisaged in RIIO-ET1 Final Proposals, indeed, an uncertainty mechanism was explicitly rejected, and the risk placed on NGET, NGET can only interpret Ofgem's position as an intention to reopen the RIIO-ET1 price control. This clearly has significant ramifications in terms of undermining the RIIO principles and removing incentives to innovate, introducing significant regulatory uncertainty, and ultimately leading to poorer outcomes for end consumers.

Ofgem has not justified its proposed application of a clawback of ET1 NLRE baseline allowance

NGET first became aware of Ofgem's erroneous proposal to clawback £556m from the ET1 NRLE allowance upon reading a single brief footnote.

In the two brief paragraphs which later follow,[8] there is no explanation given as to the basis upon which Ofgem justifies imposing the clawback. Indeed, as explained above there is no regulatory mechanism that permits Ofgem's proposed clawback of the RIIO-ET1 NLRE allowance, whether this is presented as a ET1 clawback or a ET2 true up.

In addition, it is not clear, based on the information published in Draft Determination, that there has been a consistent approach across all network companies. It appears that NGET is the only transmission licensee that is to be subject to the proposed ex-post clawback. NGET requests that Ofgem explain this approach.

It is clearly inappropriate and contrary to best regulatory practice for Ofgem to fail to explain the basis for imposing what amounts to a material financial penalty on NGET.

Ofgem has also not fully explained in the Draft Determinations how it has determined the amount of the proposed clawback. Following a discussion post-publication of the Draft Determination, Ofgem has supplied a spreadsheet setting out its calculations.

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[8] Ofgem, Draft Determination, NGET Annex, paragraphs 3.65 and 3.66 on page 63.

Notwithstanding our firm position that it is not appropriate for Ofgem to 'clawback' any amount from NGET's ET1 NLRE allowance, NGET has reason to believe why the figure cited by Ofgem would be materially lower than Ofgem suggests as a result of a number of errors and incorrect assumptions that have been identified.

Remedies

It is our expectation that the NLRE allowance proposed in Draft Determinations will increase significantly in Final Determinations through Ofgem's consideration of stakeholders' and customers' views where appropriate and use of the supplementary evidence provided to re-assess needs as well as project scope, which in turn will allow a more representative cost assessment.

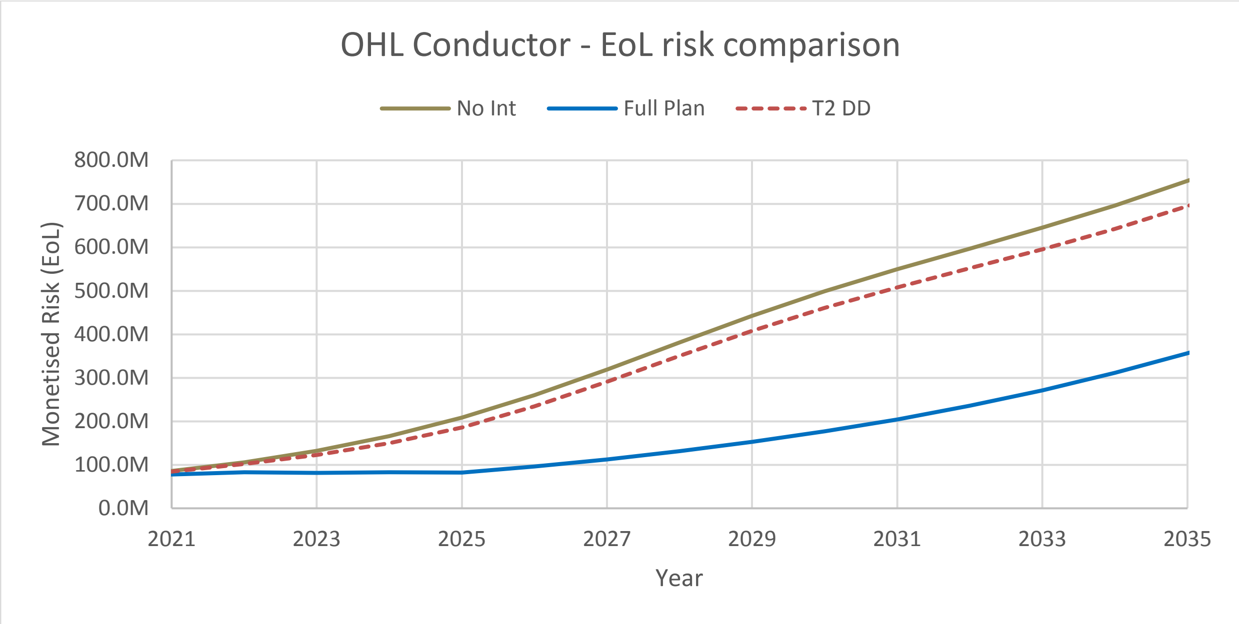
We propose that the allowances for reliability are increased in the following ways:

1. **Increase from £643m to £1.53bn**
    a. Reversal of T1/T2 crossover true-up
    b. Correction of confirmed errors and inclusion of areas with no discernible determination
2. **Increase from £1.53bn to £2.6bn (this represents our minimum for reliability)**
    a. Application of appropriate unit cost assessment methodologies
    b. Incorporation of extensive evidence for minimum reliability investments
    c. Incorporation of extensive evidence for scope driven costs
3. **Further increases to asset health driven by consideration of stakeholder requirements and economic cases**
    a. Consideration of case for greater risk reduction and robustness of Monetised Risk application and the protections it offers the consumer
    b. Consideration of directly requested stakeholder schemes – removal of Tyne crossing
4. **Removal of the T1/T2 clawback**
    a. NGET is committed to work with Ofgem to clear up this misunderstanding by securing the removal of any reference to a 'clawback' in the Final Determination and preserving the integrity of the RIIO framework.

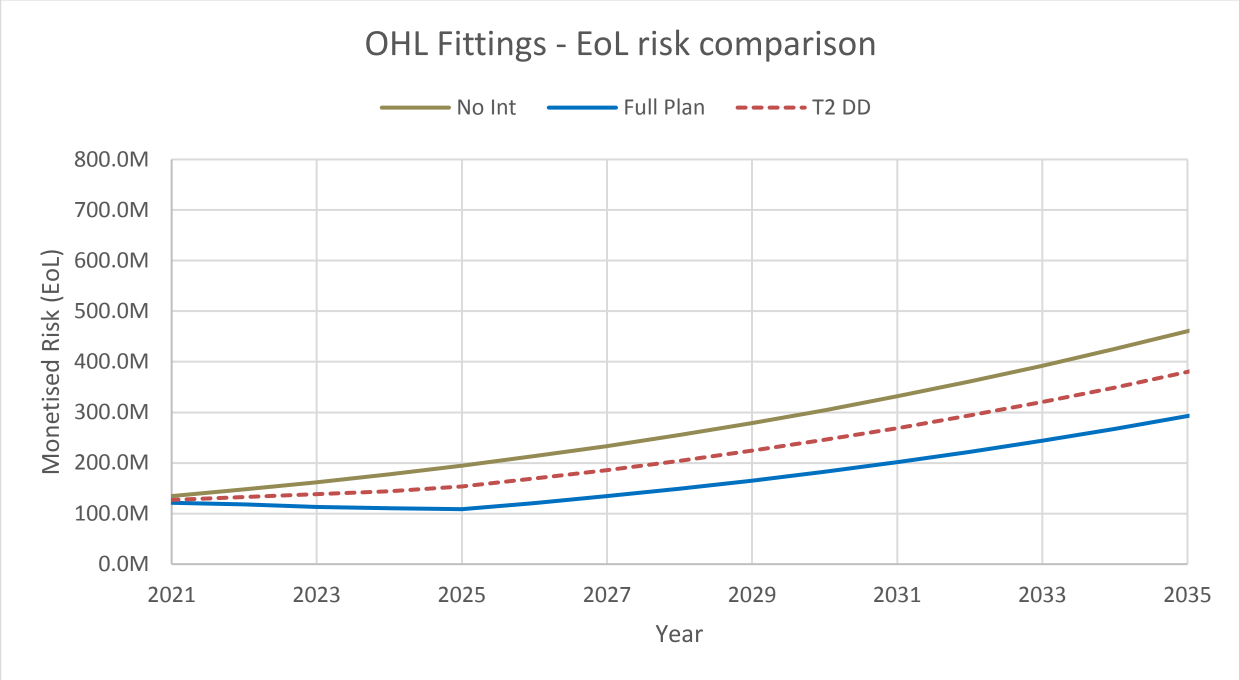
Detailed response by asset category

OHL Conductor & Fittings
BP Submission: Conductor [redacted]km, £538m – Fittings [redacted]km, £84m
DD: [redacted]km; £96m

Minimum Required: Conductor [redacted]km, £408m



The graph above shows the impact of Ofgem's draft determination for OHL Conductor on network risk. The green line shows how long-term risk would increase if there were no intervention on our OHL conductor assets in T2. The blue-line shows the reduced risk on the network based on our t2 submission. The dotted line shows the impact of Ofgem's DD, with risk being much closer to 'no intervention' and 50% higher at the end of T2 compared to the start in this category. The remaining graphs in all lead asset categories follow the same philosophy.



The graph above shows the impact of Ofgem's draft determination for OHL Fittings on network risk. At the end of T2 the level of network risk will be 23% higher in this category.

Response to Ofgem Feedback

Our plan for OHL Conductor and Fittings was driven by stakeholders wanting to maintain the T1 risk level in T2. Our submitted business plan provides what stakeholders have asked for. Ofgem's draft determination does not deliver what stakeholders have told us in this area, increasing risk on OHL Conductors & Fittings by [9]R£186.5m at the end of RIIO2.

As a minimum, If Ofgem are to focus on providing the bare minimum of investment in T2, then we would need to be adequately funded for [redacted] of circuits which include conductor and fittings, conductor only routes, and some fittings only routes to prevent short-term reliability concerns. Our supplementary evidence, published to Ofgem and on our website provides the most up to date condition data we have for these assets, and provides justification for doing this level of investment as a minimum, which for clarity does not deliver the levels of reliability requested by stakeholders.

Refreshing the network and removal of core-greased conductor is part of NGET's longer term asset management strategy (there is [redacted]km of ACSR on our network currently), thus the many alternative risk reduction options suggested in bilateral conversations with Ofgem (e.g. undergrounding motorway crossings) are not credible or economic for achieving this objective. This is in-line with the strategies of other transmission networks.

Ofgem have indicated that NGET have altered their calculation for End of Life (EoL) for OHL conductor assets, which has called into question the validity and the subsequent risk to the consumers of the submission and makes it difficult to assess the needs case

[9] R£ refers to monetised risk and not actual spend.

of the suggested volume of interventions. Ofgem further makes the point that this could be a wider risk as the methodologies developed by NGET are subject to short notice change with no independent scrutiny. This is not correct. We have not altered our calculation for conductor assets throughout the period of the RIIO2 business plan creation. There were changes agreed across the industry to the Network Asset Risk Annex (NARA) in October/November 2018 following an Ofgem-approved checking, validation and testing process. The published NARA has not yet been updated hence the methods differ slightly. The change agreed does not have an effect on the volumes proposed within our business plan.

Ofgem make a statement in their draft determination that they do not understand why deterioration rates are so high. Our evidence points to ACSR degradation as an example, which independent research by EPRI found was non-linear and had a sharp 'knee-point' as the protective zinc-galvanising is lost within the steel core. This research also found aluminium deterioration influences steel core deterioration and is a key marker for anticipating the approach of this knee-point. Our proposed T2 interventions are planned to avoid this 'knee-point', preventing a sudden deterioration in asset condition and safety, which also increase costs for replacement in the future due to the strength of the old conductor not being adequate to 'pull through' the new conductor.

Ofgem also make the point that many of these routes look very healthy. The decision to undertake the conductor & fittings together, or just the fittings only is taken following a cost-benefit analysis informing which is the option that delivers the greatest long-term benefit. This can mean in some instances that it is more efficient to accelerate the conductor replacement by a few years to align with the fittings replacement (where the fittings have reached the end of their life).

Ofgem stated that we should undertake more extensive physical sampling of our conductors in order to gain more detail on the current condition of our assets. Extensive sampling introduces additional failure risk (because a new piece of conductor has to be jointed into the span to replace the piece taken for sampling) and high relative cost in terms of resources and outages, when compared with our existing strategy.

Ofgem have applied a 40% cost reduction to our Pre-CA Allowances for OHL Conductor and Fittings. Further investigation has identified several errors and inconsistencies in the methodology Ofgem have applied to unit costs, most importantly being the use of statistically invalid benchmarks but also including the incorrect averaging of Conductor and Fittings Reduction Factors.

Arguably, our Pre-CA Allowances should have passed through the Cost Assessment stage unadjusted because there is no Ofgem benchmark for OHL Conductor or Fittings however, if these benchmarks are to be used for Final Determinations, there are further normalisation challenges relating to the input data to Ofgem's benchmark that would need to be addressed. For example:

- ☐ Other companies seem to have mapped a proportion of their Conductor Replacement cost to the Fittings asset category. This is an inconsistency in the benchmark that needs addressing because it has the impact of reducing their apparent unit cost for conductor replacement compared to NGET, and therefore our costs should be reduced less as they cover a greater scope of work.
- ☐ Other companies seem to have mapped an element of their Fittings Replacement costs to Conductor Replacement; this presumably covers the ad hoc conductor

repairs which can be required when a clamp is removed and broken wires are discovered underneath. This is not Conductor Replacement. This mapping of costs will drag down the unit cost for Conductor Replacement if it is not removed from the weighted mean and will make the Fittings Replacement cost look lower than NGET's for the same scope. (This is likely to be the major cause of the ET Sector range in unit costs for Conductor Replacement being in excess of 14,000, with a minimum of less than £[redacted] per km and a maximum of over £[redacted]m.)

- The assessment takes no account of power ratings. In general, NGET's circuits require higher ratings (and hence more/bigger conductors) than those of the same voltage being replaced by other companies. This is a fundamental cost driver.

Errors

In setting allowances for OHL Conductor and Fittings, Ofgem have been inconsistent with their own methodology and have made errors in calculation.

(i) The Deduction Factors used to calculate the CA Reductions were based on the Unit_Cost_OfgemView spreadsheet. Column N of that sheet clearly states that there is "No Ofgem UC" for OHL Conductor and Fittings. In other words, Ofgem have applied their view of efficient sector mean unit costs to NLRE, even when their own benchmarking analysis indicated that the dataset was not suitable for use and should not be used. This did not impact the DD allowances for LRE or the Scottish networks because the Project Assessment Model (PAM) passed their costs in these categories through unadjusted. NGET have therefore been treated inconsistently to the other TOs through the application of invalid cost benchmarks.

(ii) Even if these benchmark unit costs had been appropriate to use:

a. Ofgem apparently scaled the cost for allowed volumes (the Pre-CA Allowance) using an incorrectly-calculated, unweighted "average of averages" for Conductor Replacement schemes and Fittings Replacement schemes. Simply correcting the average calculation would decrease Ofgem's reduction factor from 40% to 37%.

b. However, there is no reason for the averaging; it is incorrect. Our Conductor Replacement schemes include the cost of replacing the associated fittings, as they always have done throughout historic reporting. This was clearly stated in our BPDT Narrative and Assumptions. As mentioned above, the fact that other companies seem to have removed a proportion of their cost and mapped it to the Fittings asset category is an inconsistency in the benchmark that needs addressing. This will have the impact of reducing their apparent unit cost for conductor replacement compared to NGET, and therefore our costs should be reduced less as they cover a greater scope of work. Averaging it with the Fittings Replacement Reduction Factor has the reverse impact. Conversely, our Fittings Replacement schemes replace only the fittings; there is no conductor replacement. There is therefore no logical reason to apply a ratio based on Conductor Replacement costs to Fittings Replacement. Applying the correct ratios to each category gives DD Allowances for the allowed volumes of £109.7m (as opposed to £98.4m).

c. Furthermore, there was a separate error made in the cost assessment of OHL Fittings. We quoted our units for OHL Fittings as circuit km, not tower sides. This is consistent with conductors and in line with T1 and

RRP practice, and we stated this clearly in our BPDT Narrative and the Assumptions tab. Ofgem have not corrected for this so fundamentally have assessed our costs as being three times more expensive than they are. The net effect is that NGET's OHL Fittings costs should have been assessed as [redacted] above the sector mean (all other things being equal) and not [redacted] above the sector mean. Putting this back into the allowance calculation gives DD Allowances for the allowed volumes of £130.4m (as opposed to £98.4m).

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

Supplementary Evidence

We are providing a further 29 reports to Ofgem, for OHL Conductor and Fittings, based on the feedback received since our formal submission. This includes an asset group strategy report, and 29 annexes, one for each of the routes required as a minimum to ensure short-term reliability of the network. Five Annexes cover the fittings only schemes, one for each year of RIIO-2.

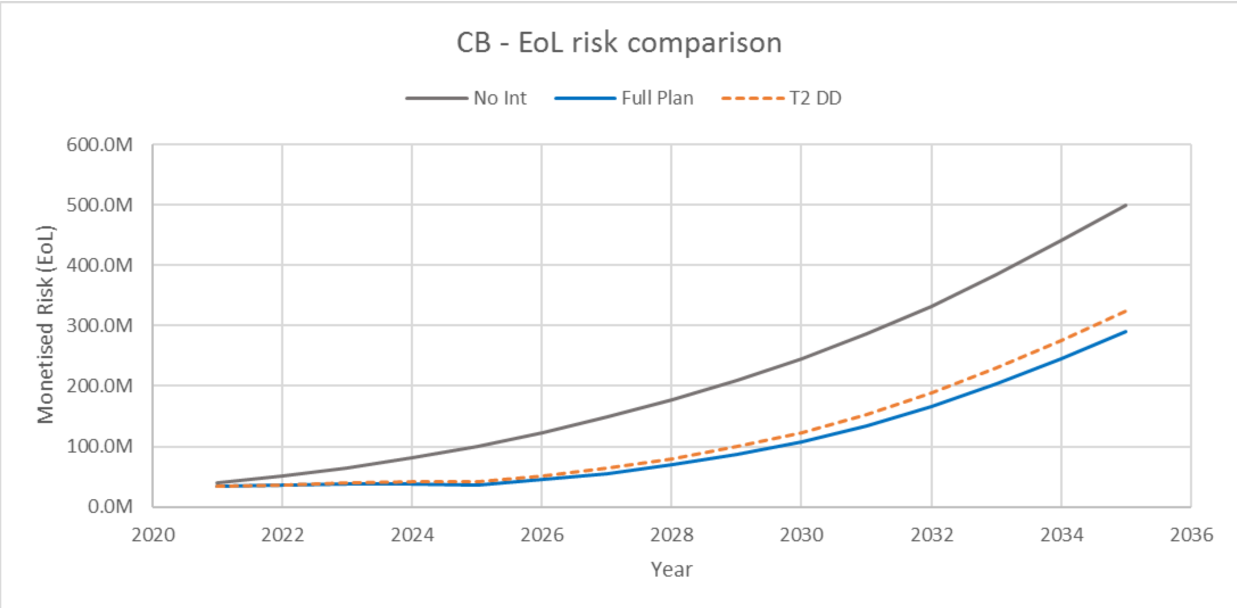
The supplementary evidence provides further detail on the justification for the routes in our business plan, making it clear whether they are driven by poor condition conductor, poor condition fittings, or a combination of both where the benefits of intervening now provide a cost reduction compared with delivering one portion separately in a future year.

The BPDT as submitted in December contains separate rows for each route for OHL Conductor replacement and so the cost mapping between EJPs and BPDT was transparent. However, all our schemes were mapped against 400kV. Some of our OHL Fittings replacement schemes were reported as a portfolio and (as mentioned above) all our fittings were reported in circuit km (to match conductor and be consistent with history). We have recut our data to reflect the operating voltage of each route, split out the OHL Fittings portfolio schemes to a row per route and restated the fittings volumes in tower sides to be consistent with other companies. This means that these investments should now flow through Ofgem's Project Assessment Model, as was the case for the other companies.

Remedy
We propose that Ofgem allow the routes identified in our minimum requirements, and further consider the additional routes which make up the gap between minimum requirements and what stakeholders requested to prevent long-term consequences on network reliability and deliverability of other programmes (e.g. net zero). We also propose that Ofgem correct the cost assessment errors mentioned above, and provide an allowance consistent with the determination of other networks.

Circuit Breakers & Bays
BP Submission: Circuit Breakers [redacted] units - bays [redacted] units; £264m
DD: [redacted]; £40m

Minimum Required: Circuit Breakers: [redacted] individual units, [redacted] site based units. Bays: [redacted] units. Total £199m



The graph above shows the impact of Ofgem's draft determination for Circuit Breakers on network risk. At the end of T2 the level of network risk will be 6% higher in this category.

Response to Ofgem Feedback
Our plan for Circuit Breakers and bays was driven by stakeholders wanting to keep the level of risk level in T2, compared to T1. Our submitted business plan does that. Ofgem's draft determination does not deliver what stakeholders have told us in this area, increasing risk on Circuit Breakers in 2026 by R£7.1m compared to 2021 levels.

An initial error was identified in the draft determination, which Ofgem confirmed as missing all costs and volumes for circuit breakers, only including costs for bays (£40m). Ofgem advised that a further £118m of circuit breakers should have been included in draft determination, resulting in a total of £158m allowed in this asset category. Using the information provided by Ofgem, it is not possible to ascertain how this cost has been derived from the volume approved.

Table 28 of Ofgem's draft determination included the following:

Asset	NGET Request (£m)	Work/volume reduction (£m)	Cost reduction (£m)	Ofgem allowance (£m)
Circuit Breakers & Bays	351.0	283.2	0	40.0

We understand that the Ofgem allowance above only included bays, and did not include £118m of allowances for circuit breakers. We also understand that the volume reduction for the circuit breakers and bays should be £193.19m, and that there is no cost reduction necessary. Total cost allowed in draft determination should be £157.81m. In addition, we cannot identify how the £40m has been determined, from the methodology used above to determine an allowed volume of bay equipment.

Ofgem's feedback on **circuit breakers** was there was limited asset specific information, with some assets being rejected where they were identified for replacement by their high consequence of failure (CoF). Ofgem were confident around costs in this area due to site visits they had carried out prior to formal submission.

Circuit Breakers are logically grouped into 'asset families', which exhibit the same failure modes and deterioration. This is a more efficient method of managing these assets compared to an asset by asset approach, which might be more beneficial for smaller networks. The condition of each asset is still determined however, and is included in the formal submission to Ofgem. The level of monetised risk on an asset is the product of the Probability of Failure (PoF) and Consequence of Failure (CoF), hence can be driven by either of these factors, or both. In our formal submission we included assets driven by CoF but did not consider options which only reduce the CoF (these were planned for the development phase, which would normally be carried out the year before intervention). We have therefore voluntarily removed these assets from our submission, although they still are reflected in our BPDTs as the tables align with our December submission.

Ofgem's feedback on **bays**, was that they strongly disagreed with the use of AAL (Anticipated Asset Life) as a metric to drive the volume of interventions, and consider this an unusable metric.

AAL is a tool which takes into account a number of physical condition factors, in addition to age to determine an anticipated technical life for an asset. This is particularly beneficial where there are high volumes of identical assets, where the costly and time-intensive process of physically examining every asset provides little additional benefit to the use of AAL. This approach is more suitable for Transmission networks with higher volumes of identical assets, and may not be suitable for smaller networks. Nevertheless, we have also completed a programme of physical condition surveys to provide further confirmation and justification for the volumes in our submission.

If Ofgem are to focus on providing the bare minimum of investment in T2, then this revised position (post error correction) would fund the bare minimum for **circuit breakers** with [redacted] individual units allowed, plus [redacted] site based units allowed. (Note this statement does not cover the switchgear associated with [redacted], see separate section for this). For **bays**; the draft determination figure of [redacted] bay assets would need to increase to [redacted] bay assets, to prevent short-term reliability concerns. We do not agree with the method Ofgem used to assess the volume of bay equipment in their draft determination. We understand that Ofgem calculated an average of 6 pieces of bay equipment per bay, and then multiplied this by the volume of circuit breakers which had been allowed. We changed our approach to bays in T1 and continue to deliver this revised strategy in T2 and beyond to manage the required 'spike' in switchgear interventions. Our revised strategy de-links the bay assets from the circuit breaker to manage the large volume of work, prioritising circuit breaker interventions in T1, and staggering the replacement of bays. Bay volumes ramp up towards the end of T1 and continue this run rate into T2, unlike circuit breakers.

At the levels of investment proposed by Ofgem in draft determination, at least one of our refurbishment centres would have to be closed, and the capability lost to continue the innovation delivered throughout RIIO1. The production line approach that our refurb. centres bring allows us to target specific families in a given period, which delivers efficiencies over alternative approaches. Losing this capability correspondingly increases unit prices, due to refurb. centre overheads and volume synergies.

Our supplementary evidence, published to Ofgem and on our website, provides the most up to date condition data we have for bay assets. It provides a clear methodology for prioritisation of [redacted] bay assets as a minimum in T2. However, this minimum would still represent a significant volume reduction from the [redacted] units requested in the baseline, and would not present a comfortable position as we have evidenced defects which correlate with increasing age.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We are providing a further 6 reports to Ofgem for circuit breakers, separating out the different families of circuit breakers, and a further 6 reports for bays, separating out the different drivers for the replacement of bay assets based on the feedback received since our formal submission.

The supplementary evidence provides further detail on the justification for the circuit breakers and bays in our business plan, making it clear that the circuit breaker plan is driven by condition. We have undertaken an intensive programme of condition assessments for our bay assets, which is included in our supplementary evidence, to provide further justification for the volumes in our plan.

In order to assist Ofgem's cost assessment, we have split out circuit breakers and bay equipment in the BPDT. This involves splitting each annual switchgear portfolio into breaker replacement, breaker refurbishment and bay works in the BPDT. Because the bay works will cover a wide range of lower-value assets which will not be completely reflected in the BPDT, a supplemental spreadsheet based on a previous SQ is also being provided.

We have already provided a similar spreadsheet for Circuit Breakers that shows cost and site by asset. Ofgem requested that NGET split BPDT circuit breaker schemes by site, so all costs associated with a site are clearly separable in the BPDT format. We have done this.

Remedy

We propose that Ofgem provide allowances for a minimum of [redacted] circuit breakers and [redacted] bays to prevent the closure of a refurbishment centre with knock-on consequences of an increase in unit costs. Ofgem should also consider the additional assets which make up the gap between minimum requirements and what stakeholders requested to prevent long-term consequences on network reliability and deliverability of other programmes (e.g. net zero). We also propose that Ofgem correct the cost assessment errors on bays, and provide a determination based on the evidence provided, and not on an incorrect assumption that interventions on bay assets are intrinsically linked to circuit breaker interventions.

Protection & Control
BP Submission: [redacted] units, £489m
DD: [redacted] units; £60m

Minimum Required: [redacted] units, £391m

Response to Ofgem Feedback

Our plan for P&C was driven by increased volumes of old electro-mechanical assets requiring replacement, and new computerised equipment with a much shorter asset life that are no longer supported and therefore require replacement. The future 'bow-wave' which a reduced investment in T2 creates, rapidly becomes unmanageable due to the shorter operating life, proliferation on the network, critical function and outage constraints. P&C plays a crucial role on the system, ensuring that faults on the network are quickly detected, made safe, and power re-routed to ensure a continued security of supply.

The proposed reduction in P&C jeopardises security of supply. With a lower level of reliability investment proposed by Ofgem in RIIO2, it is likely that faults will increase on our primary equipment which will rely on secondary protection systems to retain a secure supply of electricity to consumers. A reduction in P&C investment in addition to primary equipment has the potential for the increase in faults to cause losses of supply.

We suggest that Ofgem ensure the right balance of investment between pro-active maintenance, re-active emergency response, pro-active replacement of primary assets, and pro-active replacement of these secondary protection systems. Reductions in all these areas are currently proposed, and will in time result in lower levels of reliability.

We offered lower levels of investment in this area to stakeholders, explaining that even though these assets are obsolete and no longer supported by manufacturers, they could be pushed harder, and only replaced upon failure. Stakeholders did not want to take the risk of increased costs, longer outages and increased network risk associated with this option.

Draft determinations disallow volumes for entire P&C categories, significantly increasing network reliability risk for these assets in T2 and beyond. This does not reflect our approach to obsolescence for these categories, which is in-line with international standards and good practice. If Ofgem are to focus on providing the bare minimum of investment in T2, then we would need to be adequately funded for [redacted] units, to prevent short-term reliability concerns. Our supplementary evidence, published to Ofgem and on our website, provides the most up to date condition data we have for these assets, and provides a methodology to justify this level of investment as a minimum. The submitted plan already took on risk in managing the inevitable step up in volumes required by adopting a fix on fail approach for some 'at risk' assets. Any further reductions prevent NGET from maintaining reliability of the network in line with stakeholder expectation. We recognise the deliverability challenge; however we can be held to account for delivery through regulatory reporting and we are committed to building the capability now to ensure we can manage this inevitable volume step up for P&C. Our proposed commitment to transition P&C to a NARM framework in T2 will also provide additional protection around delivery in this asset category.

Ofgem feedback was that the needs case in this area needed substantial work, as we had only used 'three words' to justify the need. We provided detailed asset lists as part of the supplementary question process, which re-cut data already provided in the BPDT, and hence summarised the driver into three categories. The needs case was included in a 32-page justification report, providing more detail than the three words suggested by Ofgem.

Ofgem have identified IET reports which suggest busbar protection can last 100 years. This is correct, as older electro-mechanical relays are very well-built. However, as mentioned above, these relays are obsolete and no longer supported, meaning longer outages are needed to replace with more modern digital equipment. A 'fix on fail' approach could see supply losses for the duration of these outages, which is the risk our stakeholders informed us they did not want to take, and isn't reflective of the reliability consumers have told us they need. Interventions on electro-mechanical relays also represent less than 4% of the [redacted] interventions in the submitted plan.

Ofgem stated that P&C was "very, very expensive" and applied a 76% cost reduction. Arguably, our Pre-CA Allowances should have passed through the Cost Assessment stage unadjusted because there is no Ofgem benchmark. However, if an Ofgem benchmark is to be used for Final Determinations, there are normalisation challenges relating to the input data to Ofgem's benchmark. For example, other companies reported their P&C costs as Replacement. NGET created some differentiation between differing scales of intervention by using the Major and Minor Refurbishment categories to distinguish between (for example) a whole substation control system replacement and the replacement of components of a substation's protection and control system. This backfired because Ofgem calculated the weighted mean of the Replacement costs only for each company and for the sector as a whole. This meant that NGET's weighted mean Replacement cost included high-cost, large-scale interventions while the Scottish TOs' Replacement cost included all interventions down to the replacement of subcomponents. (The weighted mean unit cost for NGET was ~1900% higher than that for SPTL.)

A 76% cost reduction results in unit costs that are not credible or deliverable. Simply correcting the calculation to reflect the split between Replacement and Refurbishment would reduce this to a more credible 14%. However, this would still be applying a 76% cut to our Replacement costs which is wrongly based on a comparison between large-scale replacements such as whole Substation Control System replacements with programmes of subcomponent replacements.

We are encouraged by feedback that Ofgem expect their position to change on P&C with further evidence, which we are providing as part of this consultation response. We recognise the deliverability challenge; however we can be held to account for delivery through regulatory reporting and we are committed to building the capability now to ensure we can manage this inevitable volume step up for P&C.

Errors

In setting allowances for Protection & Control, Ofgem have been inconsistent with their own methodology.

The Deduction Factors used to calculate the CA Reductions were based on the Unit_Cost_Ofgem View spreadsheet. Column N of that sheet clearly states that there is "No Ofgem UC" for Protection Schemes. This is because the BPDT takes a range of schemes which cover different interventions and sums these onto a single row in Ofgem's cost assessment model. This resulted in a wide spread of calculated unit costs, which meant that there was no valid Ofgem benchmark for unit costs for Protection schemes. In spite of the cost assessment modelling recommending that the data should not be used to create a valid benchmark, the simple ratio of [redacted] was then used to scale all of NGET's Pre-Cost Assessment Allowances. In other words, Ofgem have applied their view of efficient sector mean unit costs to NLRE P&C spend, even when their own benchmarking analysis indicated that the dataset was not suitable for use and should not be used. This did not impact the DD allowances for LRE or the Scottish companies because the Project Assessment Model (PAM) passed their costs in these categories through unadjusted. NGET have therefore been treated inconsistently to the other TOs through the application of invalid cost benchmarks. Our Final Allowance should have been £263m for the volumes allowed in DD.

We strongly suggest that Ofgem use the data provided in our formal submission and subsequent SQ responses to make an appropriate cost assessment in this asset category; this will have to be done outside the BPDT and PAM because these do not provide adequate granularity.

We confirm that there is no over-lap with control system allowances requested within the load-related area.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

Supplementary Evidence

We are providing an additional 10 supplementary evidence reports to Ofgem, which consist of an asset group strategy report, and 9 annexes covering each of the asset types proposed for intervention in RIIO2.

This evidence sets out why our portfolio philosophy is relevant, robust and proportionate for this non-lead asset type. The evidence clearly describes the drivers including equipment obsolescence, reliability of family types, and future digitalisation and automation strategies for the transmission system.

Ofgem's cost assessment is likely to be based on historical costs, where available. The supplementary evidence provides more detail about each asset type, what they are, why the intervention is needed and the associated cost. (NGET has already provided a spreadsheet in response to SQ180 which individually lists all P&C assets with this information.) However, there are some common costs associated that need to be allocated in that spreadsheet at an asset level; in BPDT, these are at a portfolio level grouped per year per asset type. Ofgem requested that all costs in supplementary info should be reconcilable with BPDT scheme costing with a clear link to the BPDT scheme number in EJP/supporting evidence.

The majority of assets identified for T2 intervention have reached the end of their technical lives with many devices, particularly electro-mechanical or electronic units becoming unsupportable or too costly to support through maintenance alone. If we were not to replace these units during T2, the risk of failure and the impact on loss of supply and safety risk would be unsustainable.

Remedy

We propose that Ofgem allow at least [redacted] of the [redacted] unit allowed, and consider the long-term impact of not allowing the additional [redacted] required to match stakeholders expectations. We also suggest that Ofgem uses the data provided in our business plan submission, SQs and supplementary evidence to do a full cost assessment, correcting the errors of inconsistency with other networks.

We also proposed that Ofgem allow the PCD commitment to transition P&C to a lead asset in T2, as this provides further protection against the increasing volumes that we required in this area due to the smaller asset lives of modern digital equipment.

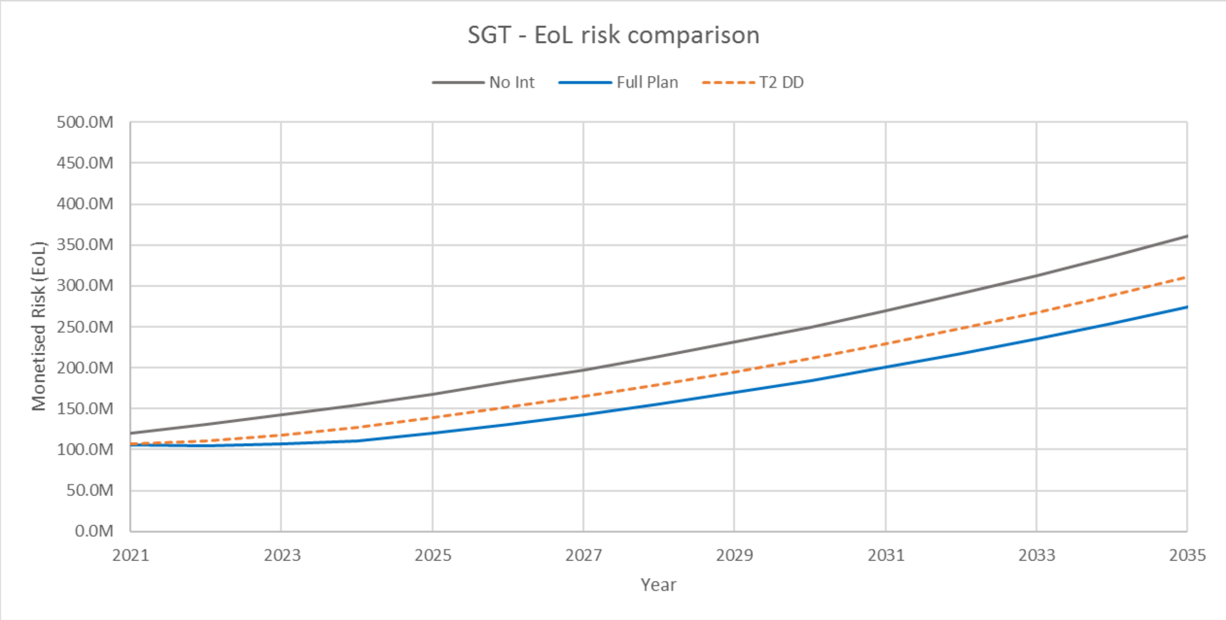
SGTs

BP Submission: [redacted] units, £253m

DD: [redacted] units; £59m

Minimum Required: [redacted] units, £157m

([redacted])



The graph above shows the impact of Ofgem's draft determination for SGTs on network risk. At the end of T2 the level of network risk will be 11% higher in this category.

Response to Ofgem Feedback

Our plan for SGTs was driven by stakeholders wanting to keep the level of risk on transformers level in T2, compared to T1. Our submitted business plan does that. Ofgem's draft determination does not deliver what stakeholders have told us in this area, increasing monetised risk on Transformers in 2026 by R£21m compared to 2021 levels.

The proposed volumes are insufficient to avoid a long-term ageing of the Wound Plant fleet. Allowed volumes and supporting narrative in draft determination are inconsistent; some SGTs and SCTs showing high 2018 EoL scores have not been allowed, in contrast to the narrative and judgement to other high EoL assets.

[redacted] is incorrectly stated as being replaced under warranty. The unit is in very poor health (EOL = 96) and needs to be in the baseline for RIIO2. Three Static Compensator Transformers require replacement in RIIO2, as detailed in NGET_A9.16 – 4.4.1. There is no reference to a determination on these assets, or what allowance has been specified for these assets.

Based on the narrative included in draft determination, it looks like the following assets should have been allowed to be consistent: 1 SGT ([redacted]) and 2 SCTs ([redacted]).

Draft determinations also does not take account of asset degradation from a 2018 asset health position. Analysis in this paper and supporting annexes evidences how assets have deteriorated from a 2018 asset health score to May 2020. This includes:

- ☐ 3 lower EOL SGTs and 1 SCT in the submitted asset list becoming high EOL units by May 2020
- ☐ Assets in the wider portfolio showing degradation since the 2018 asset health score. We therefore expect a further [redacted] SGTs as an absolute minimum to

degrade over the period becoming high EOL, which will increase network reliability risk in T2 without intervention.

As a minimum, if Ofgem are to focus on providing the bare minimum of investment in T2, then we would need to be adequately funded for [redacted] units, to prevent short term reliability concerns. Our supplementary evidence, published to Ofgem and on our website provides the most up to date condition data we have for these assets, and provides justification for doing this level of investment as a minimum. (This volume is consistent with T1 level of replacement)

Ofgem have also cited that NGET have a speculative plan which includes a blanket 'replacement' strategy. We have clearly set out the range of options we have considered, which include consideration of refurbishment which is not viable on the internal workings of a transformer. Other networks use the term 'transformer refurbishment' to refer to the replacement of ancillary parts of a transformer, which we also do but classify as repairs as per Ofgem guidance.

Ofgem remarked that all the unit costs across all voltages were higher than their sector benchmark. Further investigation has identified several errors in the methodology Ofgem have applied to unit costs, including the incorrect treatment of a bespoke [redacted] transformer at [redacted] as a standard 132kV supply point unit. This, coupled with a flawed 'average of averages' approach (see response to ETQ9 and section below for further detail), has reduced unit costs by 41%. Ofgem have acknowledged that the allowance for this asset category is not sufficient to undertake the volume allowed.

Correcting the identified errors in calculation would result in a more credible 14% reduction in unit costs, however there are then further normalisation challenges relating to the input data to Ofgem's benchmark:

- ☐ Ofgem must ensure consistency across networks in this category relating to civils, as some networks appear to have excluded most of these from the direct lead asset unit cost, resulting in an artificially lower unit price. NGET has included civils costs within the unit price, as directed by Ofgem published guidance.
- ☐ Ofgem have indicated that they will take into account additional cost evidence (e.g. to explain the marginal cost of a 400/275kV 1100MVA interbus transformer as opposed to a 400/132kV 240MVA Grid Supply Point transformer) because the mixing of these two different units into a single category has disadvantaged NGET; 40% of NGET's allowed volume for 400kV transformers are the more-expensive interbus units.

Errors

Ofgem have used a flawed approach to apply a benchmarked unit cost for transformer replacement.

i. Ofgem have calculated their unweighted "average of averages" incorrectly by inverting the ratio, averaging it and inverting the answer. A true unweighted average would be [redacted] not [redacted] (i.e. a [redacted] cost reduction, not a [redacted] cost reduction).
ii. Ofgem have incorrectly assessed the bespoke [redacted] transformer at [redacted] in their unweighted "average of averages". This double-wound unit is not comparable with the standard 132kV supply point units that are being replaced

by the Scottish TOs and should therefore be excluded from the benchmark. The fact that this unit is materially different was pointed out in our response to NGET_SQ_CA_125 and in subsequent correspondence with Ofgem. Removing this unit from the average increases the ratio again to [redacted] (i.e. a [redacted] cost reduction).

iii. Ofgem have used an unweighted "average of averages" rather than a weighted average. This gives equal weight to their unit cost for a 132kV transformer when we have none in our T2 plan (and very few on our entire network) and does not reflect the mix of voltages of units that they have allowed. Correcting this to a weighted average increases the ratio to [redacted] (i.e. a [redacted] cost reduction).

iv. Ofgem's spreadsheet "NGET Cost Assessment Works" has different values for ET Sector Weighted Means than those shared by Ofgem on 29 July as UC_OfgemView. Substituting these values decreases the ratio to [redacted] (i.e. a [redacted] cost reduction).

We included a sum of £26m to cover development works needed to commence in T2 (project management, procurement of long-lead time items etc.), but delivered outputs in T3. Ofgem have disallowed all these costs as they were deemed uncertain. These projects deliver outputs up to 8 years in the future and so are uncertain by nature. Ofgem proposed a 'true-up' mechanism for projects spanning price controls in their SSMD, but have failed to follow their own guidance in this respect.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

Supplementary Evidence

We are providing a further [redacted] reports to Ofgem, for SGTs, based on the feedback received since our formal submission. This includes an asset group strategy report, and [redacted] annexes, one for each of the SGTs and SCTs required as a minimum to ensure short-term reliability of the network.

The supplementary evidence provides further detail on the justification for the SGTs, SCTs and Reactors in our business plan. The strategy report explains why the proposed volumes are:

- ☐ insufficient to account for the deterioration in asset condition from a 2018 asset health score
- ☐ insufficient to avoid a long-term ageing of the wound plant fleet
- ☐ and why the proposed costs are insufficient to deliver the required scope of works.

The report sets out how transformers can deteriorate quickly, with the example of [redacted] transformers which were 'healthy' in December 2019, but now in a state requirement replacement based on more recent condition information. This shows the inaccuracies of Ofgem's approach which doesn't consider the future deterioration of these assets.

We have also published reports for each of the individual transformers assets we are proposing are funded for intervention in RIIO2. These reports include more information on the scope of intervention, and link to the forecast cost for each, in order to make it clearer how differences in unit ratings and non-asset scope drive our cost submission. The costs in each report are then linked to individual schemes in the BPDT; in order to make this clearer, we have recut our December submission data to split out the portfolio investments into individual schemes for each transformer. These data changes will assist Ofgem in putting the costs for this asset category through their Project Assessment Model.

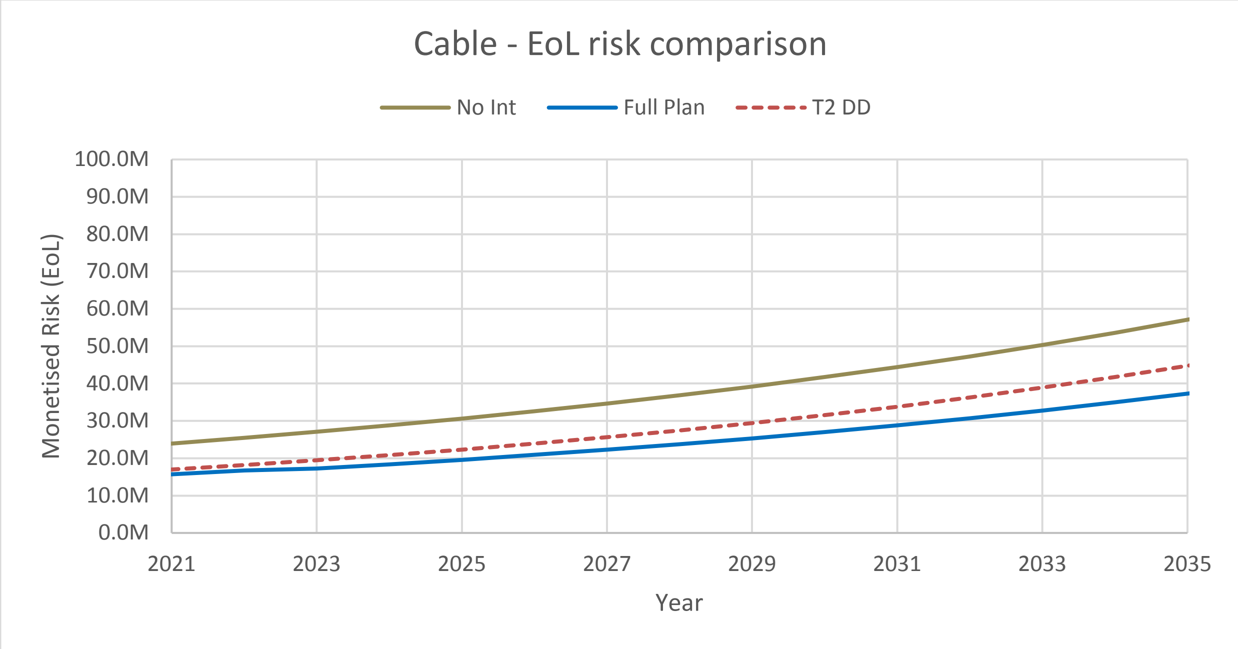
Remedy

We propose that Ofgem allow all the assets identified in our supplementary evidence as these make up our minimum requirements. Ofgem should also consider providing allowances for a further [redacted] assets which the NARM mechanism provides adequate protection for under or over-delivery (if the output is not delivered, then the allowance is returned to Ofgem, with a penalty applied if the under-delivery is not justified). Further mechanisms or protection is not necessary in this area, as this mechanism already decided by Ofgem in the SSMD is adequate.

We also propose that Ofgem correct the cost assessment errors mentioned above relating to the [redacted] transformer and unweighted average of averages approach which has resulted in insufficient allowances to carry out the volume allowed.

Cables Lead
BP Submission: [redacted]
DD: [redacted]

Minimum Required: [redacted]



The graph above shows the impact of Ofgem's draft determination for Lead Cables on network risk. At the end of T2 the level of network risk will be 9% higher in this category.

Response to Ofgem Feedback

Our plan for cables was based upon 3 specific projects (due to their size), two of these projects; Dinorwig-Pentir and LPT2 are covered elsewhere in our consultation response, this section refers only to the [redacted] project.

Ofgem questioned why these cables were reported as 'healthy' in T1, and therefore why do we need to replace them now. Ofgem are also confused as why condition monitoring on these circuits were removed in 2016, and how we can be sure that these cables are still in poor condition. Conversely, Ofgem are also questioning why the circuits were not replaced in T1. Finally, Ofgem believes the cables are healthy, even where subsidence issues are evident.

As 'lead' assets, these cables are covered by NARM, and so have a monetised risk value associated with them, which follows an Ofgem approved methodology. This methodology does not take into account specific issues such as subsidence which is the primary driver for the replacement of these cables. Independent evidence provided confirms the poor condition of the cables, with photographic evidence included as proof. Condition monitoring was removed in 2016 due to vandalism, and also as the condition of the cables had reached a point of no return.

The work to replace these cables commenced in T1, but with the majority of spend occurring in T2 following detailed development and securing of system access. Independent reports have been provided which confirm our proposal that these cables need replacing in a different location in T2.

Table 28 of the NGET Annex detailed the determination for [redacted], we presume the zero reduction is an error, and that this should be a [redacted] reduction resulting in [redacted] allowance.

[redacted]

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We have provided a further independent report, covering a recent 2020 condition survey confirming that the subsidence is still occurring, hence the driver to replace these cables continues justified in T2.

Remedy

We propose that Ofgem allow further funding for this project in T2. The subsidence nor the condition of the cables will improve, with development works already commencing in T1 following confirmation of the driver.

Cables Non-Lead & Other
BP Submission: [redacted] km, £36.3m
DD: [redacted] km; £6.1m

Response to Ofgem Feedback

Our substation cables provide crucial interconnection between primary assets (SGTs, OHLs) and substation equipment (circuit breakers and busbars), these cables are buried in the ground, often in a Cement Based Sand (CBS) mixture which whilst is good at dissipating heat (and therefore reducing the size and cost of the required cable), does mean that it is not possible to access these assets to assess the actual condition of them. Ofgem's reduction in allowances is significant in this area, and will impact on the reliability of the assets that these cables are connected to, in addition to the cables themselves.

Ofgem have stated that they need to understand the interaction with other assets (e.g. cable tails on SGTs), and they also need to compare RIIO2 volumes with TPCR5 and T1 to understand the run-rate. Our plan is based on the known condition of these non-lead assets, and where possible within the RIIO2 period we will carry out works on the primary and associated secondary assets wherever possible. However, the driver for the lead asset does not provide a driver to replace the secondary asset, or vice-versa as they often have very different asset lives hence no efficiency can be gained from aligning their replacements.

Ofgem have stated that without evidence of failure mechanisms they cannot ascertain whether the proposed works are economic and efficient. We have clearly stated the difficulty in assessing the specific condition of an individual cable, due to the fact they are buried in the ground. We have however provided further evidence, as supplementary evidence on the need and driver to replace these cables in RIIO2.

We provided more detailed information in an SQ on the 3rd June, reducing the volume of cables which we proposed to replace, which hasn't been taken into consideration in this draft determination. However, it can be seen that Ofgem applied a Cost Assessment Reduction to our original submission in their Draft Determination. If this approach is to be used for Final Determinations, and as we have explained in our responses to SQs:

- ☐ The application of benchmark unit costs on a simple "per km" basis is not appropriate for cables (where fixed costs can be greater than variable costs) and especially not suitable for the very short lengths of substation cables making up our T2 submission.
- ☐ Just grouping assets by their operating voltage is inadequate; the benchmark must correctly reflect the power rating of the circuits. In the case of cables, a need for higher ratings can result in multiple cables per phase being required, larger cross-section cables and drive the use of copper cables (due to space constraints) rather than cheaper aluminium cables.

Errors

Ofgem made the following errors in applying a benchmark to our substation cable programme:

i. The applied cost Reduction Factor of 0.474 (i.e. a 53% cost reduction) was based on a 132kV cable benchmark. None of the cables in our T2 programme are 132kV; they are all lower voltage. There is no Ofgem benchmark for 13 or 66kV cables so these costs should have passed through unadjusted. There is a benchmark for 33kV UG Cable (Non Pressurised) which is derived from ED data of which we have had no visibility; work would be required to review whether this is appropriate to use for short lengths of substation cables.
ii. Ofgem's spreadsheet "NGET Cost Assessment Works" has different values for ET Sector Weighted Means than those shared by Ofgem on 29 July as UC_OfgemView.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

As part of our response to an SQ (submitted on 3rd June), we have provided a detailed listing of the cable sections making up the proposed substation cable replacement programme for the T2 period. This included a detailed breakdown of the cost build-up on a cable-by-cable basis. We have also provided extensive commentary to explain why the application of a simple "per km" benchmark is not appropriate for cables (where fixed costs can be greater than variable costs) and especially not suitable for the very short lengths of substation cables making up our T2 submission. Ofgem have not yet provided any feedback on this reduced submission.

We are providing a further four supplementary evidence reports as part of our consultation response. Three of these cover the main asset types (MIND & Solid, Oil, XLPE) with an asset group strategy report also provided. This provides further evidence for the driver to replace these assets, setting out information on obsolescence, defect rates, and age in addition to condition data.

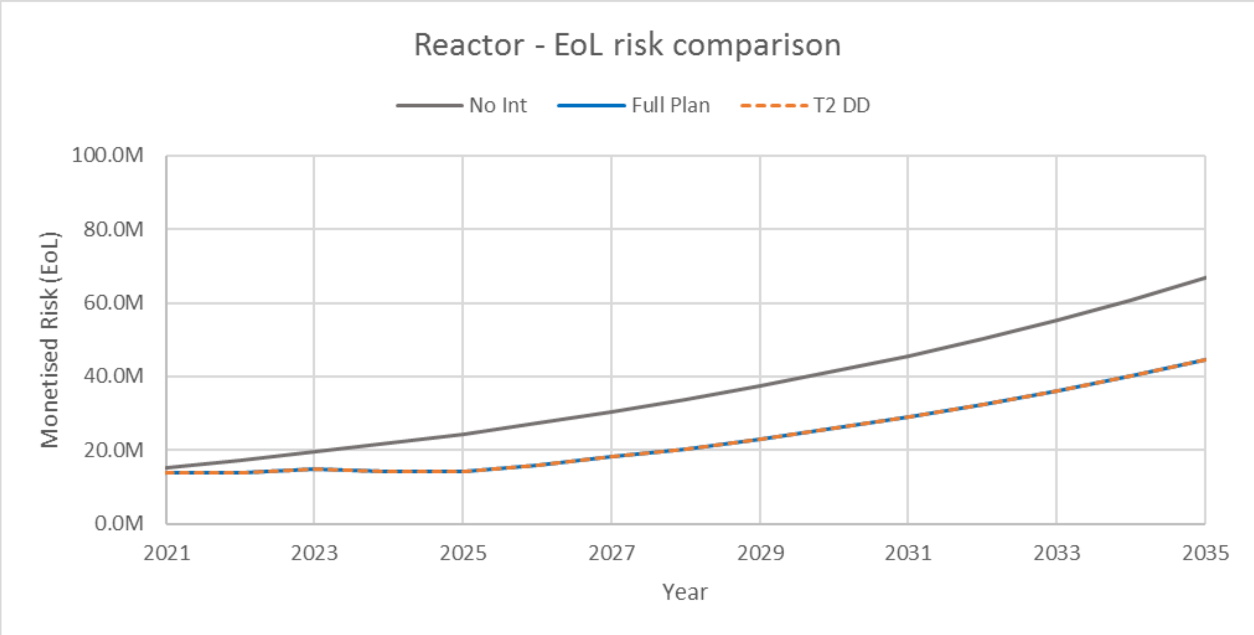
The single scheme covering this programme has been split out in the BPDT to increase clarity of the link between these reports and the data tables. We are confident that this provides the required level of detail to provide appropriate allowances for this programme of work.

Remedy

We propose that Ofgem allow the assets identified in our supplementary evidence reports, and correct the errors identified in cost assessment relating to voltage and rating.

Reactors
BP Submission: [redacted] units, £55m
DD:[redacted] units; £41m

No volume change required for FD



The graph above shows the impact of Ofgem's draft determination for Reactors on network risk. At the end of T2 the level of network risk will remain at current levels, reflecting Ofgem's approval of all the volume in this area.

Response to Ofgem Feedback
We understand that Ofgem were happy with the justification provided for reactors, and hence have not received any additional feedback in this area.

We have received a detailed list of some of the assets Ofgem have approved, which includes reactors. There are two reactors missing from this approved list, which are the two reactors at [redacted]. We understand that these were funded in the £90m of T1 projects which appeared in the Circuit Breaker correction post DD.

Ofgem's analysis indicated that the unit costs for 275 and 400kV units were higher than their sector benchmark while NGET was the only company with <132kV reactors in their T2 plan. Further investigation has identified several errors and inconsistencies in the methodology Ofgem have applied to unit costs, including the application of invalid benchmark unit costs. This, coupled with a flawed 'average of averages' approach (see response to ETQ9 and section below for further detail), has reduced allowed unit costs by 17%.

Correcting the identified errors in calculation would result in a [redacted] reduction in unit costs, however there are further normalisation challenges relating to the input data to Ofgem's benchmark:

- As for transformers, Ofgem must ensure consistency across companies in the treatment of civils, as some companies appear to have excluded most of these from the direct lead asset unit cost, resulting in an artificially lower unit price.

Errors

In setting allowances for Reactors, Ofgem have been inconsistent with their own methodology and have made errors in calculation.

i) The Deduction Factors used to calculate the CA Reductions were based on the Unit_Cost_OfgemView spreadsheet. Column N of that sheet clearly states that there is "No Ofgem UC" for Reactors. In other words, Ofgem have applied their view of efficient sector mean unit costs to NLRE, even when their own benchmarking analysis indicated that the dataset was not suitable for use and should not be used. This did not impact the DD allowances for LRE or the Scottish networks because the Project Assessment Model (PAM) passed their costs in these categories through unadjusted. NGET have therefore been treated inconsistently to the other TOs through the application of invalid cost benchmarks.

ii. Even if these benchmark unit costs had been appropriate to use:

   a. Ofgem have calculated their unweighted "average of averages" incorrectly by inverting the ratio, averaging it and inverting the answer. A true unweighted average would be [redacted] not [redacted] (i.e. a [redacted] cost reduction, not a [redacted].
   b. Ofgem have used an unweighted "average of averages" rather than a weighted average. This does not reflect the mix of voltages of units that they have allowed. Correcting this to a weighted average increases the ratio to [redacted] (i.e. a [redacted] cost reduction).

What our supplementary evidence will provide

Our supplementary evidence provides further detail for the 11 reactors allowed in our plan.

These reports include more information on the scope of intervention, and link to the forecast cost for each, in order to make it clearer how differences in unit ratings and non-asset scope drive our cost submission. The costs in each report are then linked to individual schemes in the BPDT; in order to make this clearer, we have recut our December submission data to split out the portfolio investments into individual schemes for each reactor. These data changes will assist Ofgem in putting the costs for this asset category through their PAM.

Remedy

We propose that Ofgem do not make any changes to the volume allowed, but correct the cost assessment errors relating to civils, voltage, unweighted average of averages and efficient unit costs.

Substation Auxiliary Systems
BP Submission: £75m
DD: £38m

Response to Ofgem Feedback

Ofgem have halved the volume allowed for this area, with no cost reduction. We understand that Ofgem have accepted the needs case for our battery replacement project, hence propose no deductions in this area. Ofgem have also stated that they are not 'over the line' on our proposals for LVAC boards and Diesel Generators yet, and have not approved any of the assets listed as requiring replacement in the 5-10 year period (0-2 years and 2-5 years have been approved). Ofgem require further information why these have been included in the plan, and also how many of the 5-10 year assets are proposed for replacement in RIIO2.

There are [redacted] LVAC boards, and [redacted] diesel generators that require replacement in the next 10 years due to their asset health, we are proposing to replace [redacted] of the LVAC boards and [redacted] of the diesel generators in RIIO2, leaving the remainder to be replaced in RIIO3. This is further detailed in our supplementary evidence provided as part of this consultation response.

We provided an answer to SQ181 in May, which removed [redacted] LVAC assets in our plan. We also responded to SQ181 which removed [redacted] diesel generators from our plan. It is not clear whether this has been taken into consideration in DD. SQ144 highlighted [redacted] assets that required minor capex, which is also unclear from DD whether these are funded or not through DD.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We are providing 4 additional reports for our substation auxiliary assets, an asset group strategy report, and detailed annexes covering Batteries, LVAC boards and Diesel Generators. These address all the feedback from Ofgem to date and provide justification for the interventions proposed in our business plan.

Remedy
We propose that Ofgem address the changes in volume identified through the SQs, and allow the 5-10 year assets that are proposed in our business plan now that feedback has been provided, as requested.

London Power Tunnels
BP Submission: [redacted]
DD: [redacted]

No change required for FD

Response to Ofgem Feedback
Ofgem stated that the LPT2 project justification report is a good example of what they would like to see for all projects, as it is fully developed and has high cost confidence through the use of actual tendered costs.

We welcome the full funding of this critical project to the security of supplies in London. We would like to stress that this project has had significant amounts of development, which is not efficient to do for all assets in our business plan.

Dinorwig – Pentir Cables
BP Submission: [redacted]
DD: [redacted]

Minimum Required: [redacted]

Response to Ofgem Feedback
Dinorwig pumped hydro power station is a critical lynchpin of the GB Electricity System, providing fast response to faults, and crucial frequency response services. It is connected to the transmission system through two cable circuits, which have a history of faults and failures. The outages needed to carry out these constant repairs are costly, information from the ESO CBA included in our formal submission stated,

[redacted]

Ofgem have not allowed this project in the baseline, instead proposing that it is suitable for competition, within the LOTI uncertainty mechanism. Firstly, the LOTI mechanism is specific to Load related projects (this was confirmed by Ofgem in a LOTI workshop in Feb 2020). Secondly, Ofgem state that the project was not assessed for competition within our formal business plan submission. This is an error, as Page 106 of our business plan, figure 9.21 shows our assessment of 4 projects (LPT2, Dino-Pentir, [redacted] Cables and Substation Cables) against Ofgem's criteria for competition (of New, High-Value and Separable), and further assessed the project using the criteria of Time Criticality, Certainty of Need, and Scope for Innovation.

[redacted]

Dino-Pentir has programmed works that align with the local generator, which includes substation works at two sites, and also includes tunnel works which make it neither new or separable. It is time critical, and has limited scope for innovation therefore was assessed, using these criteria Ofgem's own criteria, as not being suitable for competition.

The time and cost criticality of this circuit results in the need for it to be included within our baseline for RIIO2. We have already commenced development works in RIIO1 on this project, but have had to put work 'on hold' until a decision can be made by Ofgem and provide us certainty to proceed.

On the needs case, Ofgem have fed back that the condition of the cables are not reflected in the monetised risk scores. We have explained to Ofgem that the methodology to calculate the risk scores for cables has been approved by Ofgem, and is published on their website in the Network Asset Risk Annex (the NARA). The methodology is common for all cables, hence there will always be specifics which the common methodology does not cover. An example of this is the ground conditions for the [redacted] Cables (as mentioned previously). The volume of faults and repairs on these particular cables, coupled with the specific consequence of failure costs related to constraints are not fully reflective in the common methodology, hence we have made these clear in the justification provided for these circuits.

In contrast to this assessment, Ofgem has:

- ☐ stated that the justification paper was good, and that they were happy with the proposed option to increase the number of cables to 3, which we welcome as this would provide greater protection against constraint costs in the future
- ☐ questioned why we haven't invested in T1: we have invested in T1, with the project commencing in 2015. It is for this reason that we now need to stop work on this project, until we get confirmation of funding from Ofgem.

In addition to the error above that we hadn't assessed this project for competition, Ofgem have also incorrectly stated the investment value as [redacted] instead of [redacted]. We understand that this error has been recognised by Ofgem.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business

Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We are providing an update to the already 'good' justification report, providing further details of the competition assessment that was carried out, and further details of the current deteriorating condition of the cables.

Remedy

We propose that Ofgem include this project in the baseline. Consumers are protected from non-delivery of this particular project as we have 'ring-fenced' the project within the NARM framework (categorised as A3).

Instrument Transformers
BP Submission: [redacted] units, £63m
DD: [redacted] units; £17m

Response to Ofgem Feedback
We welcome Ofgem's proposal to make no adjustments to allowances driven by legislation on PCBs. However there are more PCB assets in our plan than Ofgem have allowed, therefore we have clarified this further in our supplementary evidence.

Ofgem have stated that for interventions driven by condition, that they may not deteriorate to the extent that they would need intervention in T2. The evidence we have provided does indicate that these assets will need replacing in T2, and we highlight to Ofgem that we do not think that Ofgem should be taking additional risk which contradicts the views of stakeholders and consumers.

As with other categories, Ofgem have not allowed any assets which are due to be replaced in the 5-10 year period. It is essential that the volumes proposed in our business plan are allowed in Ofgem's final determination. There are [redacted] assets categorised in the 5-10 year timeframe which are not included in our T2 plan, they will need to be replaced in T3. In addition, there are another [redacted] assets that have a clear driver for replacement in T3 also. A restriction in T2 allowances in this area will result in undeliverable volumes in the medium-term, with knock on consequences to network risk and reliability.

Ofgem's analysis concluded that the unit costs for instrument transformers were higher than their sector benchmark. Further investigation has identified errors and inconsistencies in the methodology Ofgem have applied to unit costs, including the application of invalid benchmark unit costs. This, coupled with a flawed 'average of averages' approach (see response to ETQ9 and section below for further detail), has reduced allowed unit costs by [redacted]

Errors
In setting allowances for Instrument Transformers, Ofgem have been inconsistent with their own methodology and have made errors in calculation.

i. The Deduction Factors used to calculate the CA Reductions were based on the Unit_Cost_OfgemView spreadsheet. Column N of that sheet clearly states that there is "No Ofgem UC" for Instrument Transformers. In other words, Ofgem have applied their view of efficient sector mean unit costs to NLRE, even when their own benchmarking analysis indicated that the dataset was not suitable for use and should not be used. This did not impact the DD allowances for LRE or the Scottish networks because the Project Assessment Model (PAM) passed their costs in these categories through unadjusted. NGET have therefore been treated inconsistently to the other TOs through the application of invalid cost benchmarks.

ii. Even if these benchmark unit costs had been appropriate to use:

   a. Ofgem have calculated their unweighted "average of averages" incorrectly by inverting the ratio, averaging it and inverting the answer. A true unweighted average would be [redacted] not [redacted] (i.e. a [redacted] cost reduction, not [redacted]

b. Ofgem have used a simple, unweighted "average of averages" rather than a weighted average. This does not reflect the mix of voltages and types (CTs, VTs, etc) of units that they have allowed. It will be necessary to correct this calculation to use a weighted average for Final Determinations.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We are providing a further 5 supplementary evidence reports in this area, comprising of an asset group strategy and 4 detailed annexes covering each of the key drivers for replacement.

These reports include more information on the scope of intervention, and link to the forecast cost for each, in order to make it clearer how differences in unit ratings and non-asset scope drive our cost submission. Costs per asset and any other associated costs reported in the BPDT will be provided in supplementary information spreadsheets that reconcile with the costs in the BPDT schemes.

The costs in each report are then linked to individual schemes in the BPDT; in order to make this clearer, we have recut our December submission data to split out the portfolio investments into schemes grouped by the four key intervention drivers (PCB, SF6, etc). This approach has been confirmed with Ofgem. These data changes will assist Ofgem in carrying out a more-appropriate cost assessment.

Remedy

We propose that Ofgem include all the units driven by safety legislation, and condition driven units with a 5-10 year timeframe to prevent future deliverability problems.

We also proposed that Ofgem correct the cost assessment errors with unit cost benchmarks, and unweighted average of averages.

Through-Wall Bushings
BP Submission: [redacted] units, £14.3m
DD: unknown volume; £10.4m

Response to Ofgem Feedback

Ofgem have provided feedback that there were a large number of bushings funded in T1, and it was unclear how this fed through into T2. Ofgem were also unclear whether these assets exceeded their asset lives in T1, or due in T2.

Our formal submission clearly set out that the vast majority of these assets were installed in the late 1960s, hence a 'spike' in replacement should be expected in T1/2/3 timescales. We undertake an annual asset health review which takes into consideration age and health of these assets, in addition we carry out forensic analysis on de-commissioned assets to further evidence the condition of the assets. We have also innovated in this area in T1, using online condition monitoring technology. This has resulted in much smaller numbers requiring replacement than a pure 'age-based' methodology.

We are proposing to replace just [redacted] of the total population of through-wall bushings ([redacted] units) in T2, [redacted] of which are already in a condition that require replacement. A further [redacted] assets are predicted to be in a condition requiring replacement in T2.

Volumes will need to increase again in T3 due to the age profile described earlier. We are confident that we will innovate to prior to this period to minimise the allowances requested, as we have done in T2. However a reduction in allowance in T2 will result in more emergency work and outages in T2 and T3, reducing system access for crucial net zero interventions.

What our formal business plan submission & SQs actually included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide

We are not providing any further evidence in this area, we are confident that the evidence provides sufficient justification for the volumes requested.

Remedy

We propose that Ofgem include [redacted] units as a minimum, as these are currently in a condition that requires replacement. We also propose that Ofgem consider a further [redacted] units to cover assets which deteriorate between 2018 and 2026, and to prevent an undeliverable volume in RIIO3.

Tyne Crossing
BP Submission: [redacted]
DD: [redacted]
Stakeholder requirement: [redacted]

Response to Ofgem Feedback

The Tyne Crossing project has been the result of considerable discussion between NGET and Ofgem over the past 12 months. We have clearly set out that our licence requires us to remove the Tyne Crossing when instructed by the Port Authority. This often results in significant constraint costs, and disruption to the network which are costs seen by consumers.

The port authority informed us some time ago of the increasing number of crossing removals needed, as supply of windfarm jackets, which are crucial to the delivery of the nation's net zero commitments, are increasing now. Alongside a detailed report from the ESO, we have proposed a permanent undergrounding solution which reduces costs to consumers.

We asked Ofgem to make a decision on this project prior to T2, however Ofgem proposed to include a re-opener in the T2 business plan instead. We wrote to Ofgem and explained that this was unacceptable to our customers, that the need case is there now, and as a minimum needed to be included in the baseline for RIIO2.

We are therefore disappointed that Ofgem have incorrectly stated that a re-opener was previously agreed, this is not the case. We are also disappointed that Ofgem are proposing to delay the decision, which will have consequences to manufacturing facilities in the North East which benefit the GB economy and transition to net zero.

We urge Ofgem to include this project within the baseline for RIIO2 to prevent the consequences mentioned above.

What our formal business plan submission & SQs included

The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

Remedy

We propose that Ofgem include this project in the baseline.

Strategic Spares
BP Submission: £46m
DD: £46m

No change required for FD

Response to Ofgem Feedback
Ofgem have approved our strategic spares proposals in full. Whilst we welcome this determination, continued reductions in all areas of reliability will result in more 'fix on fail' scenarios requiring the need for a much higher spares holding.

Towers & Foundations
BP Submission: £197m
DD: £128m

Response to Ofgem Feedback
Ofgem approved funding in this area only covers painting (which is an essential maintenance item, as the coating used provides corrosion protection and extends the asset lives of these critical assets). Ofgem stated that they were 'not sold' on grade 4 steelwork recovery, which is a grade showing levels of corrosion which normally require more costly replacement of the steelwork. In RIIO1 we have worked with our suppliers on an enhanced coating system, which means we have been able to recover 100% of grade 4 steelwork at a £140m lower cost than replacement.

Our RIIO2 submission bakes in these savings for consumers, with allowances lower than T1 in this area as these lower costs become business as usual. By not allowing these costs for grade 4 steelwork recovery, and also not including costs to replace them either, Ofgem are increasing the risk and cost to consumers on towers in RIIO2.

Ofgem correctly highlighted in their draft determination that there is the possibility of significant crossover with OHL conductor, fittings and extreme weather in our plans. Through the process of answering supplementary questions, and the detail explained in supplementary evidence reports (we have listed each asset and route we will be working on) we have clearly shown that there is no 'double-funding' of any work in this area in RIIO2.

What our formal business plan submission & SQs included
The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide
We are providing a single asset group strategy report covering further detail on our proposed work on towers and foundations in RIIO2.

Remedy
We propose that Ofgem include the allowances requested in this area in RIIO2. Our costs show a saving in comparison with RIIO1, and embed innovation into RIIO2. Volumes are consistent with RIIO1 which show a consistent refreshment rate across our network.

Condition Monitoring
BP Submission: [redacted] units, £22m
DD: £14m

Response to Ofgem Feedback
Ofgem provided verbal feedback that in principle they supported our proposals for condition monitoring. However, Ofgem stated that there was not enough detail on where integrated sensors will be deployed, what the benefits were, what type of sensors were going to be used and what the overarching strategy is.

Our strategy is to increase and enhance the capability to monitor asset condition and performance variables in real time, which will enable a more targeted and proactive asset management approach. In RIIO2, we will deploy sensors on bays and circuits that are stressed mechanically and or/electrically, or that are operationally critical allowing us to intervene at the optimal point and maintain the reliability that stakeholders and consumers inform us is their number one priority.

What our formal business plan submission & SQs included
The following table highlights the level of detail provided in our December formal submission, which we consider to meet the requirements set out in Ofgem's Business Plan Guidance document. Further evidence is being provided following feedback received after submission of our business plan.

[redacted]

What our supplementary evidence will provide
We are providing a stand-alone strategy report for integrated sensors, providing further detail of what we will provide, where we will install them, why we are installing them there, and the benefits of installing them.

We carried out our most extensive stakeholder engagement programme to date for RIIO-2, asking what stakeholders and consumers wanted at every stage of our business plan development. Our formal submission in December 2019 reflects exactly what stakeholders and consumers have informed us. Ofgem have ignored what stakeholders want, instead deciding to promote a headline bill reduction, even where this has a negative effect on reliability and optionality for net zero.

Remedy

We propose that Ofgem include the full allowance for this area. Ofgem support the use of condition monitoring, which will in turn allow us to increase the detail captured on the condition of our assets, an area which Ofgem have indicated they needed more of in our RIIO2 business plan submission.

NGETQ13 Do you agree with our proposed allowances in relation to non-operational capex? If not, please outline why.

For Information Technology and Telecoms (IT&T) Ofgem propose a baseline allowance of £143.6m with a further £149.4m subject to an uncertainty mechanism, where it is proposed that the UM will be a re-opener at the start of the T2 and a mid-period re-opener. The cost reduction of £44m from our Business Plan submission of £337m is based upon an assessment of the maturity and cost certainty of proposed investments undertaken by Atkins. We believe that the maturity assessment sets an unreasonable expectation of how far our proposed investments have progressed through our governance process, given we do not yet have certainty of funding.

Of the projects currently funded in baseline we have seen an efficiency reduction of c 23% applied. We are not aware of any evidence (either historic or based on industry best practice) to support these arbitrary levels of cost adjustments, whilst there is evidence to suggest that project over-run is as likely, if not more likely than delivering for less than forecast cost. Reductions of the order of 23% risks leaving us unable to deliver project scope, which in turn can lead to inefficiencies in business operations which will compromise our service to customers and stakeholders. We believe that providing allowances close to submitted proposals provides a strong incentive to deploy world class project management and controls to deliver project scope to time, cost and quality and to avoid costly over-run.

Supplementary evidence has been provided to Ofgem (NGET_A14.07_ET IT Supplementary Evidence) to update on project status and cost and resource certainty which should result in costs being re-instated if the Atkins methodology is applied in a consistent manner.

The use of re-openers provides flexibility and helps to manage uncertainty, however appropriate ex-ante baseline funding is essential for efficient IT investment. In particular, funding for investments shared between regulated entities eg NGET and NGGT, should be incorporated in the baseline to provide certainty of cost and delivery, as this approach is in the best interest of consumers. Similarly, investments required in the first two years of the T2 period should be included in baseline to allow these projects to be initiated without delay. For example, initial funding to cover the initial stages of the SCADA replacement project should be included in baseline, with subsequent costs determined following an RFP process allowed through a re-opener.

Assuming re-openers are managed efficiently and without undue delay, required baseline funding for NGET is £285m.

We recognise the importance of Information Technology and Telecoms investment in underpinning Digitalisation Strategies and would encourage Ofgem to ensure clear alignment between digitalisation aspirations and IT investment.

We note the Ofgem proposal for the ESO to 'implement a new autonomous IT model from the beginning of the 2023-25 Business Plan'. NGET shares a number of applications and services with ESO and any move to an independent model is likely to have capex and opex costs for NGET which have not been considered as part of our Business Plan submission and will require inclusion via the re-opener at the start of T2 or via another mechanism.

We agree with Ofgem's proposal to allow £10m for Property non-operational capex

For vehicles and transport, please refer to NGETQ6.

NGETQ14 Do you agree with our proposed allowances in relation to network operating costs? If not, please outline why.

Summary position

We do not agree with Ofgem's draft proposals for Network Operating Costs.

The Faults, Inspections and Vegetation Management categories of Network Operating Costs (NOCs) have been assessed in line with our business plan submission, which we support.

However, the Repairs and Maintenance, Legal and Safety, and Operational Protection Measures and Operation IT Capex categories show significant disallowances at the draft determination stage, which we do not agree with. Ofgem's draft positions are based on a partially completed cost assessment process for NOCs, which has been frustrated by the mixed opex / capex composition of the Repairs & Maintenance and Legal & Safety categories in Ofgem's Business Plan Data Tables (BPDTs). This approach arises from fundamental changes to Ofgem's cost reporting classifications for RIIO-2, which we had raised concerns over when proposed.

Ofgem impose a stage 3 Business Plan Incentive (BPI) penalty for the Flood Mitigation element of the Legal and Safety category, the Operational Protection Measures and IT Capex category, and the Repairs & Maintenance category. On the grounds of inadequacies in the business plan assessment stage, issues relating to changes in cost reporting structures, and limited supplementary questions, we think this is unreasonable.

An opex escalator is proposed for NOCs which looks to recognise the incremental impact on opex of capex projects delivered through uncertainty mechanisms. We support this in principle but think that the mechanism needs to recognise legitimate scale differences between NGET and the Scottish TOs which are not reflected in Ofgem's proposals.

Summary of Ofgem's draft proposals for NOCs

The high-level outcome of Ofgem's draft determination for NOCs as defined by Ofgem's T2 Business Plan Data Templates, is a 53% baseline disallowance against our submitted plan, as summarised in the table below. This increases to 56% when inclusive of Ofgem's additional ongoing efficiency target.

Table Reference	NGET Submission (£m)	Ofgem Propsed Baseline Allowance (£m)	% Baseline Disallowance	Allocation of proposed ongoing efficiency target (£m)	Post ongoing efficiency disallowance (£m)	% Post ongoing efficiency disallowance
C2.20 Faults	1.0	1.0	-	(0.1)	0.9	(7%)
C2.21 Inspections	94.0	94.0	-	(6.4)	87.6	(7%)
C2.22 Repairs and maintenance	415.9	209.0	(50%)	(14.2)	194.8	(53%)
C2.23 Vegetation management	29.6	29.6	-	(2.0)	27.6	(7%)
C2.24 Legal and safety	244.8	153.3	(37%)	(10.4)	142.9	(42%)
C2.25 Operational Protection Measures & Operational IT Capex	186.9	62.1	(67%)	(4.2)	57.9	(69%)
C2.26 Visual Amenity	202.4	-	(100%)	-	-	(100%)
Total Network Operating Costs	1,174.6	549.0	(53%)	(37.3)	511.7	(56%)

Ofgem has allowed our submission for Faults, Inspections, and Vegetation Management without adjustment, which we agree with.

The Legal and Safety category encompasses our proposals for flood mitigation. Our substantive position on the flood subcategory is included in NGETQ5. We make further reference to flood mitigation in our position on BPI penalties below.

Our submission for Operational Protection Measures and Operational IT Capex is reduced by 67%. Our December Business Plan Submission identified a requirement for £186.9m capex investment for OpTel Refresh, with £108.9mm identified for Telecoms equipment replacement, implementation of a high bandwidth overlay and other enhancements and £78m to replace fibre-wrap which is approaching the end of its service life. Ofgem's Draft Determination 'does not fully accept the need case for OpTel refresh at present' and does not differentiate between fibre-wrap and telecoms equipment refresh and proposes £62.1m allowance a 'to enable works to begin'. This represents a reduction of 67% and will mean that obsolete telecoms equipment will remain in service presenting a significant risk to the reliability and resilience of the electricity transmission network.

The OpTel network is a highly resilient telecommunications network providing secure connectivity between substations and control rooms, and connects DNO's, Generators and TO's in Scotland. OpTel underpins critical tele-protection services and network monitoring and control (services and is essential to the safe, secure, reliable and economic operation of the electricity transmission network. [redacted]

Loss or compromise of the OpTel network could lead to a loss of visibility, control and protection of our sites, resulting in a partial or complete loss of supply. In the event of a Black Start event OptTel provides the secure communication channels that enable us to effectively coordinate activities to restore electricity transmission when other communications networks are not available due to loss of electricity supplies.

The OpTel Telecoms equipment was installed between 2011-14 and some assets will be over 15 years old by the end of T2 when Telecoms operators typically replace after 10 years. We are extremely concerned that the consequence of reduced and/or delayed funding will mean that obsolete telecoms equipment remains in service into the T3 period with an unacceptably high risk of in-service failure and an increased cyber security risk to this CNI designated asset, which poses a serious risk to the reliability and resilience of the electricity transmission network.

Following submission of our Business Plan in December 2019 we have been working on our approach to OpTel telecoms equipment and fibre-wrap replacement. Recognising the different drivers for telecoms equipment refresh and fibre-wrap replacement we have split these into discrete projects and provided supplementary evidence to Ofgem in support of our plans. We believe that it is essential that the obsolete telecoms equipment is replaced as per our Business Plan Submission and have been working to develop a revised approach for fibre-wrap replacement using enhanced condition monitoring and an innovative approach to fibre-wrap deployment, which requires reduced investment and system access in the T2 period. This approach will enable ageing fibre-wrap to be prioritised and replaced over a seven-year programme at the lowest cost to the end consumer and with minimal system outage requirements, ensuring that the reliability and resilience of this essential service is maintained. The High Bandwidth Overlay (HBO) is required to meet growing demand for capacity due to additional services eg cyber security of operational technology (OT) and increasing data volumes eg asset condition data. The HBO is not constrained by the fibre-wrap replacement programme as stated in the Atkins Engineering report and is most efficiently delivered as part of the Telecoms equipment refresh works.

The revised costs are based on T1 actuals where available, supplemented with supplier and unit costs from our EHub and are summarised in the table below:

	Dec 2019 BP Submission (£m)	**Ofgem Draft Determination (£m)**	**Proposed Final Determination (£m)**
Fibre-Wrap Replacement	78.0	62.1	37.1
Telecoms Equipment Refresh	77.4		77.4
High Bandwidth Overlay	19.8		19.8
Control Telephony Refresh	8.0		8.0
Performance & Security Enhancements	3.7		3.7
Total	**186.9**	**62.1**	**148.0**

17% of the reduction relates to Visual Amenity schemes. This allowance has not been assessed during the business plan evaluation and relates to spend approved in T1 but spanning T1/T2 period. Our position in this is covered in our response to consultation question NGETQ7.

Implications of significant allowance reductions on core activities

Significant disallowances for Repairs and Maintenance (50%) and Legal and Safety (37%) were signposted in Ofgem's draft determination, which strike at the heart of our core direct opex activity and would be unsustainable for the fulfilment of our statutory duties and electricity transmission licence obligations. For Repairs and Maintenance, it appears that much of what Ofgem has allowed relates to capex elements, leaving 72% of the core direct opex activities for this category disallowed. This rises to 74% when inclusive of an allocation of Ofgem's ongoing efficiency target.

We acknowledge that the Draft Determinations allow funding for our inspection activities which will enable us to continue to address legal requirements such as Pressure Systems Safety Regulations and Provision and Use of Work Equipment Regulations. In addition, this allowed finding for inspections will enable us to collect condition data on assets essential for informing our interventions.

However, cutting repairs and maintenance to the extent proposed compared to historic levels cannot possibly result in stable performance in terms of asset risk or reliability. The consequences of this reduction will be far reaching and felt in both the short and medium-term with a real possibility that it cannot be corrected in the long term.

As maintenance activities address safety and environmental consequences associated with asset unreliability as well as reliability, at the proposed level of allowance we would be required to direct the limited funding we have to enhanced mitigation. This mitigation will be required to manage the safety risks posed to our own staff, contractors and the public as well as risks to protecting the environment to ensure we comply with our legal requirements. The effect of the Draft Determinations is to increase these risks beyond the ALARP (As Low as Reasonably Practicable) levels as required by the HSE (Health and Safety Executive) and Regulations 4 (maintained to prevent danger) and 5 (where strength and capability may giver is to danger) of the Electricity at Work Regulations.

The cost of these enhanced risk mitigations will reduce the available money for maintenance further exacerbating the requirements for enhanced mitigation and also drive up capex unit costs for work occurring on site where enhanced mitigations are in place.

Inherent redundancy and designed resilience in the network mean individual failures will not automatically lead to a supply interruption, however, the potential to ultimately impact the reliability experienced by consumers and directly connected customers is materially increased, particularly in times of system stress such as extreme weather events when multiple co-incident failures can occur.

Escalating risk levels on the network are at odds with stakeholder requirements and may not be recoverable in the longer term. Our proposed Business Plan aimed to hold risk levels stable on the network, by contrast, the proposed levels of maintenance drive up risk levels.

Given the above it is essential we are given the requested level of funding for network operating costs, especially as the risks of reductions in this area and the risks associated with the reduced replacement and refurbishment funding are compounded.

Background context to Ofgem's draft determination positions

Our main responsibility as a transmission owner is to ensure a safe and reliable transmission network. Our network needs to be available to our customers when they need it allowing the provision of secure power supplies for their consumers.

To fulfil this role, we need to keep our assets in a healthy condition by continual assessment, intervening at the right time to either undertake policy defined maintenance, refurbishment or replacement of the assets. The NOCs category includes all of the direct operating expenditure that underpins these critical activities. By baselining our business plan to 2018/19 underlying performance, our submission in this regard was anchored to the highest level of unit cost efficiency achieved in RIIO-T1 to date. We provided a separate business plan annex for total opex

(NGET_A14.17_Total Opex Annex) which described the underlying drivers behind our direct opex submission.

Ofgem's T2 regulatory Reporting Instructions and Guidance (RIGs) stipulations, coupled with the totex based orientation of its Business Plan Data Tables (BPDTs) mean that the Repairs & Maintenance and Legal & Safety sub categories of NOCs are comprised of both opex and capex components. We understand that this is not unique to our submission, with SPT and SHET's submissions for NOC also having a blend of opex and capex activity.

Our capital plan submission was supported by a series of Investment Decision Packs (IDPs) which have an asset / investment type orientation and provide justification for the expenditure proposed. Expenditure on certain asset types are grouped together in the IDPs, however interpretation of the RIGs means that a single IDP can straddle multiple BPDTs. As illustrated in table below, a single IDP may not exclusively relate to NOCs categories, including elements that are contained within the Non-Load Related Capex submission.

5 year totals in £m (2018/19 prices)	Non Load Capex	Repairs & Maintenance	Legal & Safety	Total Capex in IDP
NGET_A9.21__Substation auxiliary systems IDP	39	36	0	75
NGET_A10.05_Extreme Weather IDP	0	0	60	60
NGET_A9.10__Non-Lead Substation Other and Other TO equipment IDP	28	91	91	209
NGET_A9.03__Circuit Breakers and Bays IDP	0	3	0	3
Total Capex Included in BPDT	67	130	151	347

This has proven to be problematic for Ofgem's Engineering Team, who provided feedback that our submission was difficult to understand and interpret, also expressing a concern of overlaps or double counts in our submission. This has led to a partially completed cost assessment for the capex elements of Repairs & Maintenance and Legal & Safety feeding into Ofgem's draft determinations, with the opex elements of these tables effectively unaddressed. We are actively working with Ofgem's Engineering and Cost Assessment teams to resolve this.

Our submission was consistent both in its interpretation of the T2 RIGs, and in the resulting expenditure profiles contained within. The structured and sequenced approach to our business plan formulation, coupled with data assurance activities, ensured that there were no duplications or overlap of activity within our submission. It is the completion of the data tables and IDPs in line with RIGs that seems to have caused the data to be unclear for Ofgem's engineering team. This was a risk we raised when the data table formats were first proposed by Ofgem.

Since our submission in December 2019, we have proactively engaged with Ofgem's Engineering and Cost Assessment teams to provide any clarifications or additional justification required to complete a robust assessment of our NOC plan. However, most of the supplementary questions we received on NOC related to Operational Protection Measures and Operational IT capex, with only three specifically relating to other categories.

Finalising the cost assessment process for NOCs

We observe that Ofgem's business plan assessment process is not well suited to dealing with data tables of a mixed opex / capex composition. Indeed, the techniques used to assess the different expenditure types vary, and Ofgem recognise this distinction in their stated cost assessment methodology.

It is unfortunate that this has impeded the completion of the cost assessment for NOCs, but the issues are not insurmountable, and we are committed to working with Ofgem to resolve the situation ahead of final determinations.

Pivotal to this is the clear separation and distinction of the capex activities contained with NOCs. We have provided Ofgem with a reconciliation of IDPs to BPDTs for the affected categories, which demonstrates that whilst proposed capex spend for asset classes affects multiple BPDTs, there are no overlaps or double counts in our submission.

Whilst we provided a separate annex on direct opex with our original submission and received limited supplementary questions on this area, we have developed a supplementary NOC annex to support Ofgem's completion of the cost assessment. This consolidates information provided in the original submission with information provided through the SQ process and expands on the composition of the NOC submission at table level. This is provided as an appendix to our consultation response.

Alongside this, we will provide Ofgem with "opex only" views of the relevant BPDTs to facilitate a separate cost assessment appraisal of these given the differences in approach that are adopted for opex and capex.

Providing Ofgem with additional clarity on the scope and boundary of the NOC capex components still leaves remaining issues as to how these should be assessed. The inference is that these would follow the approach intended for direct opex, which we note would be inconsistent with the treatment of other capex. Again, we will continue to engage with Ofgem's teams on this ahead of final determinations.

Our engagement with Ofgem since publication of the draft determinations has been constructive and positive, and this has enabled us to develop views on how the cost assessment process could be enhanced to deal with particular issues that present, resulting in a robust and consistent appraisal of NOCs.

Ofgem has agreed to ongoing engagement on the assessment of NOCs beyond the Draft Determination consultation response deadline. This will help to ensure a robust appraisal that both Ofgem and NGET can stand behind.

Ofgem's approach to assessing direct opex

We observe that Ofgem's cost assessment for direct opex is very much anchored to T1 performance, and involves the following steps:

i) Calculation of unit cost of each sub category of NOCs costs at the disaggregated level observed historically over the six-year T1 period to date

ii) Calculation of the average T2 unit cost forecast per submissions at same level of disaggregation

iii) The minimum of the T1 observed or T2 forecast unit cost is taken

iv) The minimum unit cost per (iii) is then multiplied by the networks view of forecast volumes

v) Where volumes are not reported, the same approach is taken but with average annual expenditure instead of unit costs

This is a highly mechanised approach which presents pitfalls if used in isolation:

- Ofgem should be cognisant that the T2 volume data requirements are a new requirement, and not part of T1 regulatory reporting requirement. This has required networks to derive a volume history retrospectively, as described in our NOC supplemental annex. Ofgem should take this into consideration in its unit cost appraisal, and cross check its line item level appraisal against a table level review.
- By anchoring its assessment to the average of T1 performance, this mechanised approach overlooks the case made for specific upward cost pressures we foresee in T2. Details of these were provided in our original submission but have been reconfirmed with additional narrative in our supplementary NOC annex.
- Furthermore, T1 actual positions could be affected by non-recurring factors that might suppress one particular year of performance, but do not endure on an underlying basis. Anchoring the T2 appraisal to the lowest position in T1 could therefore incorrectly assume that these factors are present on an enduring underlying basis.
- It is also important to note that network operating models evolve over time, so to anchor to a low point in T1 at line level may result in an outcome that does not reflect ongoing steady state.
- Unlike the assessment of capex, Ofgem performs its direct opex assessment inclusive of efficiencies that are embedded into forward cost projections. The outcome is then fed into a separate calculation of ongoing efficiencies, giving rise to the likelihood of double count with network's own proposals in this regard. It is vital that Ofgem duly considers the sequenced formulation of our plan in its appraisal, which can be summarised as follows:
  - i) Our underlying forward cost projections were baselined to 2018/19 performance, exclusive of exceptional severance costs arising in that year. This reflects an underlying position reflective of the current shape of the organisation, and the optimal level of unit cost efficiency achieved in T1 to that point.
  - ii) We separately considered upward cost driver risks, overlaying these to the underlying position in T1. We should stress that these are specific cost pressures that would not be captured through general inflation uplift, RPEs, or Ofgem's proposed NOC opex escalator.
  - iii) Our projections were then overlaid with enduring efficiencies we expect to deliver from 2019/20 onwards, the value of which was higher than our on-going efficiency assumption for the RIIO-2 period. There is therefore overlap with Ofgem's separately calculated ongoing efficiency target, which effectively runs from 2019/20, with two years of compound efficiency carried throughout the T2 period.
  - iv) We applied an ongoing efficiency assumption of 1.1% from 2021/22 onwards based on closing T1 levels inclusive of embedded efficiencies to this point. Again, this creates overlap with Ofgem's own ongoing efficiency proposals

  It is therefore important that Ofgem's cost assessment takes due consideration of our plan build to ensure that due consideration is made for the case for upward cost pressures, and that embedded efficiencies are not double counted within Ofgem's separately calculated ongoing efficiency target.

There is a logical way to navigate through these issues to arrive at an appropriate assessment of direct opex that is more consistent with the approach for capex, and that allows Ofgem to overlay its ongoing efficiency challenge without risk of double count. This would take the following steps:

1. Assessment of our submission on an underlying basis exclusive of T2 upward cost pressures and efficiencies embedded from 2019/20 onwards in the first instance.
2. The appropriate reference point for the T2 appraisal is 2018/19 exclusive of exceptional severance costs, and not any position prior to this. This reflects the current shape of our organisation, and a position of optimal unit cost performance in T1 up to this point. This also solves the issue of non-recurring factors affecting reported positions in the years prior to 2018/19 – any alternative approaches to addressing this issue would be complex, involving explicit adjustment for agreed items, and a risk of being non-exhaustive.
3. Whilst we think our proposal would negate issues involved with retrospectively creating volume history, for the avoidance of doubt, a table level cross check of outcomes could be made against the line level assessment.
4. We think it is inappropriate that the effects of specific upward cost drivers are rolled into Ofgem's unit cost assessment, as they could be systematically discounted through reference to lower 2018/19 positions, and automatically and unduly be deemed as inefficient. We therefore propose that the case made for these is separately reviewed and overlaid to the outcome of steps 1 to 3.
5. The outcome of step 4 can then be subject to Ofgem's ongoing efficiency calculation.
6. Given the strength of our embedded efficiency proposals from 2019/20 onwards, there is a possibility that this will result in outcomes higher than our cost proposals. If this is the case, we propose that Ofgem defaults to the lower of steps 1 – 5 and our original proposals.

We think this approach resolves a number of the pitfalls associated with Ofgem's stated cost assessment methodology for direct opex, retaining a core element of initial core modelling, but overlaid with suitable cross checks and overrides where appropriate.

This approach would require submission of specific recuts of our data submission, which we have committed to providing to Ofgem. Based on engagement with Ofgem's cost assessment team, an opex only view of the submission for Repairs and Maintenance and Legal & Safety would be required in any event in order for it to carry out its stated cost assessment methodology, given mixed table composition issues highlighted previously.

We have discussed this approach with Ofgem's cost assessment team for consideration in arriving at final determinations.

Stage 3 Business Plan Incentive penalties

Our view is that Ofgem’s proposed stage 3 penalties for NOC are unreasonable in the light of complexity associated with the data submission, and the limited degree of supplementary questioning particularly for direct opex and flood mitigation. They should therefore be reversed.

- **Flood mitigation**: In our December submission we explained that we had applied bandings to estimate the total cost of our programme of works, to include full and localised protection. These were provided in the justification paper.

  These bandings were based on an exercise where we took an initial view of the range of potential solutions required e.g. full site protection, single building protection, raising of a kiosk etc. This initial view was based on the EA / NRW flood maps, Flood Risk Assessments (where available), satellite images and existing knowledge of the sites. A low and high case cost was applied to each type of mitigation based on average costs of works of a similar scale delivered during RIIO-T1.

  We received only one SQ for extreme weather requesting us to provide a best current view of the sites which will require flood defences as well as detail for each project the scope of works. No questions were submitted on our proposed bandings. There was also limited detail within the Draft Determinations NGET Annex p.23 where Ofgem’s justification for the rejection was on the scope of works. We therefore consider the 10% Stage 3 BPI penalty on flood mitigation proposed in Ofgem’s DD is unjustified.

- **Repairs & Maintenance**: we believe that the issues encountered with the assessment of this category are more driven by changes to Ofgem’s cost reporting classification and the totex oriented structure of the BPDTs than a failure to justify the proposed expenditure. It is clear that Ofgem’s assessment process is not designed to take account of data tables with mixed opex / capex composition, and this does not represent any failure on our part. We have provided Ofgem with detailed reconciliation of IDPs to BPDTs and can demonstrate unequivocally that there are no overlaps or double counts in our submission. We received a very small number of supplementary questions relating to direct opex, and actively engaged with Ofgem to ensure it had what it needed in this regard. Although we accept that there is complexity involved, we think Ofgem has had ample opportunity to investigate and appraise our plan in the six months following our submission, however we remain committed to ongoing constructive engagement with Ofgem to support its data interpretation issues. We therefore consider the 10% Stage 3 BPI penalty on repairs & maintenance expenditure proposed in Ofgem’s DD is unjustified.

- **Operational Protection Measures & Operational IT Capex**: Our December submission set out proposals for the replacement of fibre-wrap as it approaches the end of its service life, the replacement of obsolete telecoms equipment and the implementation of a high bandwidth overlay (HBO) to segregate operational and business services and cater for significant growth in data volumes. We provided further information to Ofgem through the SQ process to address timeline and delivery queries amongst other things. Ofgem’s Draft Determination NGET Table 11, pg 23) stated that they ‘do not fully accept the need case for OpTel Refresh at present ….. and have concerns over the deliverability of the proposal’. Ofgem proposed baseline funding ‘for only the final two years of RIIO-2 to enable NGET to begin this work’.

We are surprised that Ofgem consider OpTel works to be of a lower cost confidence due to the bespoke nature of operational protection measures and IT work, as we have provided information explaining that our costs are based on previous actual costs from telecoms equipment refresh and fibre-wrap replacement costs based on actual costs from the BT21CN project and equivalent earth-wire works from our T1 overhead line replacement programme. We have provided further supplementary evidence to Ofgem in support of our OpTel proposals, confirming costs for Telecoms equipment and HBO implementation, and proposing an innovative approach to fibre-wrap replacement which does not require a system outage and therefore addresses deliverability issues. and can be achieved at lower overall cost. This approach will enable ageing fibre-wrap to be prioritised and replaced over a seven-year programme at the lowest cost to the end consumer and with minimal system outage requirements, ensuring that the reliability and resilience of this essential service is maintained. We therefore consider the 10% Stage 3 BPI penalty on operational protection measures & operational IT capex proposed in Ofgem's DD is unjustified.

NOC opex escalator

Ofgem propose an opex escalator mechanism for NOCs that recognises the incremental impact to operating costs arising from capital projects delivered via uncertainty mechanisms. We are supportive of the principle of this approach but propose that there is further work required to calibrate the mechanism appropriately.

Ofgem has shared its calculations supporting the proposed 0.5% of RAV uplift, which compares T1 NOC positions for 2013/14 to 2018/19 from the T2 BPDTs to RAV figures as published in network RFPR submissions. The resulting analysis shows broad consistency between SPT and SHET, but NGET with a higher NOC to RAV relationship. Ofgem has taken the average of the Scottish TOs to inform its position, treating NGET as an outlier.

Our first observation is that Ofgem is using NOC per the T2 BPDTs, which as a consequence of cost reporting classification changes, and the totex oriented structure of the BPDTs means that these values include elements of capex. This capex will have been added to the RAV in T1. If Ofgem wishes to reflect the **opex** impact of RAV growth arising from uncertainty mechanisms, it should compare opex to RAV, and not the blended position contained in the BPDTs. A suitable alternative would be to substitute NOC for direct opex per the T1 RRP submissions, as this would better capture the essence of the relationship Ofgem want to capture. It therefore follows that the escalator should apply to NOC opex, and not any capex element.

Secondly, the RAV comparator should be that reported through the PCFM each year, and not any adjusted position per the RFPR which could be distortive. This protects the purity of the relation between opex and RAV growth as incurred.

Finally, by taking the Scottish TO average, Ofgem is overlooking legitimate scale differences with NGET which manifest in different relative sizes of opening RAV, and its relationship to direct opex. There are many factors that give rise to this, for instance:

- Difference in historical investment levels
- Difference in historical totex performance levels

- ☐ Geographical dispersity of assets
- ☐ Concentration of assets in higher load bands
- ☐ Concentration of assets in more densely populated areas
- ☐ Higher number of generation connections
- ☐ Higher number of DNO interfaces
- ☐ London effects

The list is not exhaustive, nor is it simple to adjust for. However, this cannot simply be ignored, as to do so would result in a mechanism that is penalising to NGET.

Whilst Modern Equivalent Asset Value (MEAV) is a less than perfect comparative scale measure, this could play a role in calibrating the NOC opex escalator mechanism appropriately.

Ofgem could assess the direct opex to RAV relationship on a sector basis in the first instance to establish the average position. This could then be weighted to networks based on MEAV. This could result in a network specific mechanism that duly takes account of scale differences.

We would also recommend that Ofgem takes account of the latest available direct opex and RAV positions in its calibration of the mechanism, as data for the 2019/20 reporting year is now available.

Conclusions

In making its final determinations, Ofgem should:

i) Consider the supplemental evidence we have provided which reconciles the capex elements of Repairs & Maintenance and Legal & Safety to IDPs and BPDTs.
ii) Separately assess the capex and opex elements of Repairs & Maintenance and Legal & Safety based on the recuts of the BPDTs we have provided.
iii) Consider the appropriate mechanisms for assessing the capex elements of NOC and their consistency with the broader capex cost assessment methodology.
iv) Perform its cost assessment of the opex elements of NOC on an underlying basis in the first instance (i.e. exclusive of upward T2 cost drivers and embedded efficiencies).
v) Give separate consideration to the case made for specific upward cost drivers impacting NOCs opex in T2 to ensure that these are not systematically discounted via its mechanised unit cost assessment process.
vi) Overlay its view of ongoing efficiency on NOCs opex pre-efficiency positions to ensure that there is no inadvertent double count of proposals made by networks in this regard.
vii) Recognise where changes to reporting structures, complexity in activity and underpinning data, and limited supplementary questioning have played a role in Ofgem's business plan assessment process and remove its position on Stage 3 BPI penalties accordingly.
viii) Consider our proposals to better calibrate the NOC opex escalator mechanism, in particular given due recognition of legitimate scale differences between NGET and the Scottish TOs.

NGETQ15 Do you agree with our proposed allowances in relation to indirect operational expenditure? If not, please outline why.

We do not agree with proposed allowances in relation to indirect operational expenditure because Ofgem's decision to disallow £427m Closely Associated Indirects (CAI) costs and £20.2m Business Support Costs (BSC) is based solely 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.

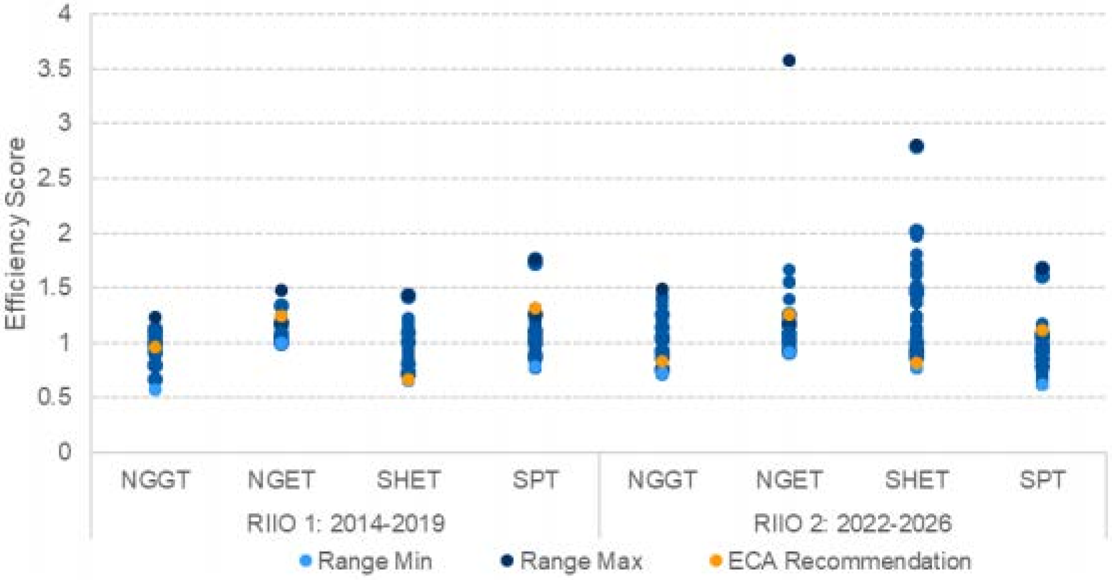
Retaining this decision at final determinations will place an additional £50m efficiency challenge on closely associated indirect costs that were already 17% lower than on average in RIIO-1, an equivalent reduction of £73m across the RIIO-2 period: way beyond a reasonable view of stretching efficiency. The resulting allowances for what amounts to 46% of our operational and capitalised labour costs would require a sharp reduction in engineering roles that that have historically been in high demand and short supply, threatening our future workforce resilience.

Whilst regression models can be useful within a broader toolkit of approaches to help 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 NGET CAI costs in RIIO-2 could fall anywhere between 0.91 to 3.58.
- 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 the costs of carbon offsetting, despite Ofgem agreeing to the need for those higher levels of cost drivers elsewhere in their determinations such as the costs we need to take forward our Environmental Action Plan commitments.

- 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.

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 CAI and BSC plan costs fall within the confidence intervals 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 heed the advice of their consultants to recognise the limitations of econometric modelling as it relates to the Transmission sector. Ofgem should not rely on flawed and unreliable econometric modelling to set allowances but should instead place the greater weight on evidence submitted by networks for the efficiency of their 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 limited upward cost pressures we foresee in RIIO-T2. For indirect capitalised costs this would mean assessing as part of capex unit costs, as we set out in our response to ETQ9. On the basis that our submitted CAI costs were 17% lower on average than RIIO-1, and our BSC costs benchmarked to upper quartile efficient costs we would expect Ofgem to allow our submitted costs in full.

Ofgem's models have poor statistical fit

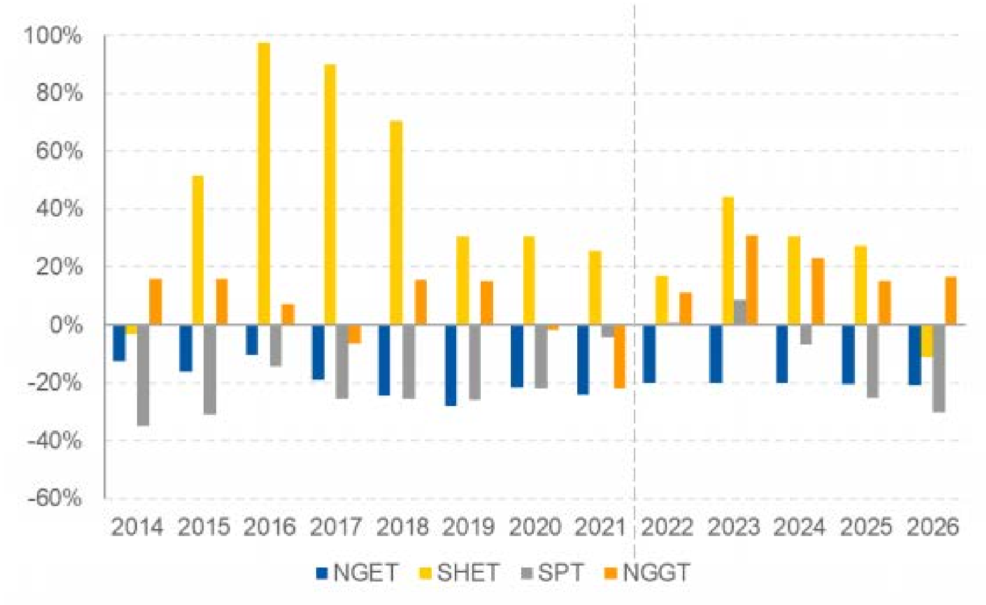
As we set out above, we fundamentally disagree with Ofgem's decision to set allowances for indirect activities based on a regression model approach that seeks to compare the costs of fundamentally different networks, is highly sensitive to modelling decisions and statistically flawed. We set out our 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 is submitted alongside our response. NERA found a number of significant flaws with ECA's preferred statistical model 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."

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

The regression approach adopted here is fundamentally limited by the poor comparability of the four transmission companies Ofgem has chosen to pool together in their assessment. As illustrated in the figure below the regression model is asked to predict costs for two smaller Scottish TO's and the significantly larger NGET and NGGT transmission companies. NGET's apparent inefficiency across a number of model forms tested by ECA is a function the regression line having to pass through the middle of the two larger NG companies and of NGET having slightly higher CAI/MEAV costs than NGGT. This doesn't necessarily imply that NGET's costs are inefficiently occurred, rather ECA's chosen cost drivers of capex and MEAV do not wholly explain the differences between NGET and NGGT's CAI costs, which we demonstrate below.

Ofgem's Modelled CAI vs. Average T2 MEAV and Line of Best Fit

Source: NERA analysis of Ofgem's Cost Assessment File

ECA themselves acknowledge that despite passing the model selection criteria the small sample size on which their models are based could lead to the regression result changing significantly and recommend to Ofgem that, specifically with regards to NGET its model should only be used as a "basis for challenging NGET", a recommendation which we agree Ofgem should follow in making their final determinations.

Ofgem have set allowances on models that incorrectly assume 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 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. Reperforming the CAI model without GT resulted in the coefficient on capex ceasing to be significant whilst the MEAV coefficient was twice as high. 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. As a minimum, for final determinations Ofgem should remove NGGT from the regression analysis on the basis of different relationships for CAI and BSC costs than the ET sector. Given that the relationship between capex and MEAV cost drivers changes for the ET companies as a result of this removal, Ofgem should again adopt extreme caution in relying on the results of any ET sector regression analysis to set allowances, in line with the recommendations made by ECA.*ECA's preferred models fails important specification tests and so may over or under estimate efficient costs*

ECA's report shows 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.

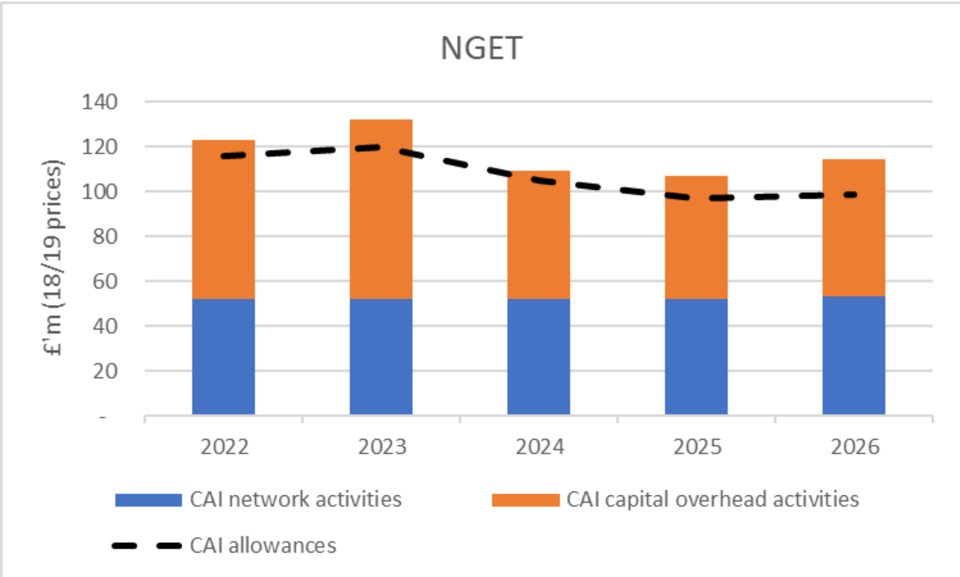
Whilst we disagree with the classification of these tests as not of high importance, we recognize that alternative FE and RE models suggested by the failure of these tests are less able than POLS to deal with the small number of observations that ECA has been asked to model and we show below that the modelled coefficient is highly sensitive to the choice of model form. Our evidence here points again to 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 driver.

In their apparent concern about the potential noise from capitalisation policies Ofgem has 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. These net operating costs equate to over a quarter of our business plan submission for CAI or, after adjustment for the lower capex baseline in Ofgem's determination, just under half of the CAI costs required for the RIIO-2 period. Ofgem's determination represents an 8% challenge across our CAI activities, or a total of £50m reduction against our submission for net operating costs that were at their lowest point since the beginning of the RIIO framework, on average 17% lower than RIIO-1.

Net and capitalized CAI costs (adjusted for DD baseline capex volumes) versus gross CAI allowances



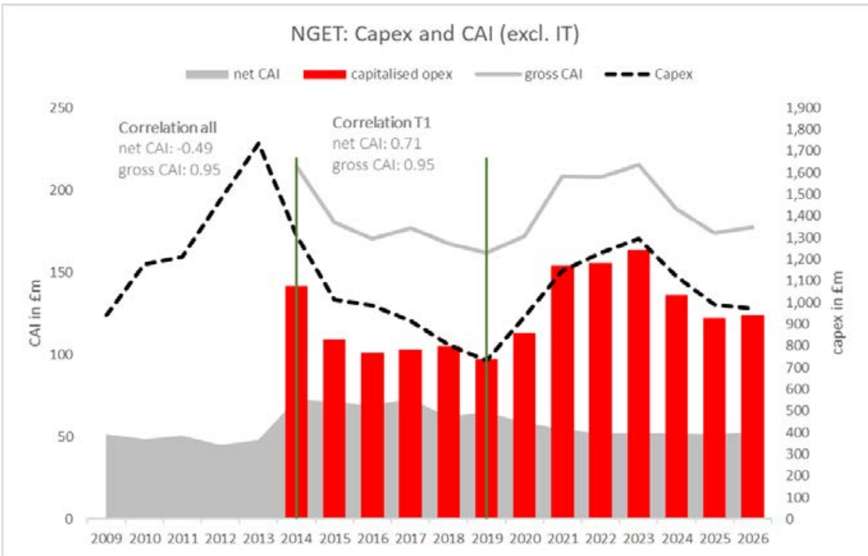
In making their final determination Ofgem should assess the costs of the ongoing operation of our network separately from indirect capital costs, recognising that these activities are not driven by capital workload. As we set out in our response to ETQ9, indirect capital costs should be assessed as a total capex unit cost, so as not to prejudice the impact of different delivery models on the proportion of direct and indirect costs.

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 fell steadily through RIIO-1 as we identified efficiencies within our operating model and implemented a more targeted training operational training. This broadly coincided with a reducing capex profile over the same period as London Power Tunnels 1 project was completed and as we identified efficiencies in our planned asset health programme.

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 recognize 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".

Historical and forecast net and capitalized CAI costs and capex expenditure. A positive correlation is not observed outside of the six years of actual RIIO-1



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 £52m 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. ECA noted "implied efficiency scores for NGET appear to be an outlier in the regressions" but rejected the inclusion of a dummy variable for NGET in their final model because they felt it was unjustified based on, amongst other things, an untested presumption that that the only unobserved effects were scale-related and therefore already controlled by MEAV. However, our analysis makes clear 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.

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. 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.

The NGET Transmission network is over three times the length of either of the Scottish Electricity Transmission networks and covers six separate Distribution network operator regions. In RIIO-1 we have delivered on average over asset health 120 interventions on the network each year and our business plan forecast this to rise to around 200 interventions each year in RIIO-2. Managing this programme so as to mitigate the impacts to customers and other stakeholders requires dedicated Delivery Optimisation teams supported by bespoke planning tools that are not needed in other Transmission networks where the potential for interactions between interventions and DNO's is far more limited. In advance of RIIO-2 we undertook a bottom up process review of all of our CAI activities, resulting in new organizational structure and working practices which bring our costs 17% lower on average than in RIIO-1. The poor ability of the MEAV cost driver to predict the costs of ongoing operation of our network is explained in part by the greater complexity of operations required to run the NGET network. ECA have shown that inclusion of an NGET dummy variable to control for these factors resulted in the coefficients for capex and MEAV becoming insignificant, for this and the other regression limitations we have already raised above we recommend that Ofgem should not place reliance on regression analysis in setting CAI allowances for RIIO-2 and instead assess costs related to network companies own historic cost performance with consideration of upward cost driver evidence.

Ofgem have not considered evidence of future changes in cost drivers

In our business plan we provided evidence of upward cost pressures in our insurance premiums and modest additional costs to meet our net zero ambition by the end of RIIO-2. In setting allowances directly from regression models Ofgem have not considered the evidence in these areas and so have omitted to set allowances.

Insurance

Our business plan included insurance costs of £75m for the RIIO-2 period, representing an increase on average £4m per annum from RIIO-1. This was driven by changing insurance premiums, the cost of which represent over 95% of our total insurance costs. The increase can largely attributable to our property damage (including business interruption) premiums which will rise when the Captive current long term reinsurance arrangements expires in March 2021.

The reinsurance premium rates have been held broadly flat since 2017in 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 £4m 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.

Carbon offsetting - £2.5m

We included costs of £2.5m in 2026 for carbon offsetting of our capital activities. Using our current estimates for T2 and the carbon impact of historically tracked schemes in T1, we estimate that our forecast £870m of capex in 2025/26 will equate to a maximum of 180,000 tonnes of CO2. A value of £2.5m to offset these 180,000 tonnes of CO2 in 2025/26 has been estimated, using an approximate carbon price of £13/tonne of CO2 and assumes this offsetting is achieved through afforestation. This estimate is based on the average of two quotes, one from the Woodland Trust to purchase 750,000 trees to offset the 180,000 tonnes at £2.7m and the second from the carbon trust at £2.3m. We had strong stakeholder support for our ambition to achieve net zero by the end of the RIIO-2 period.

Ofgem should fund the modest incremental costs to meet our net zero ambitions, for which we have strong stakeholder support, in their final determination.

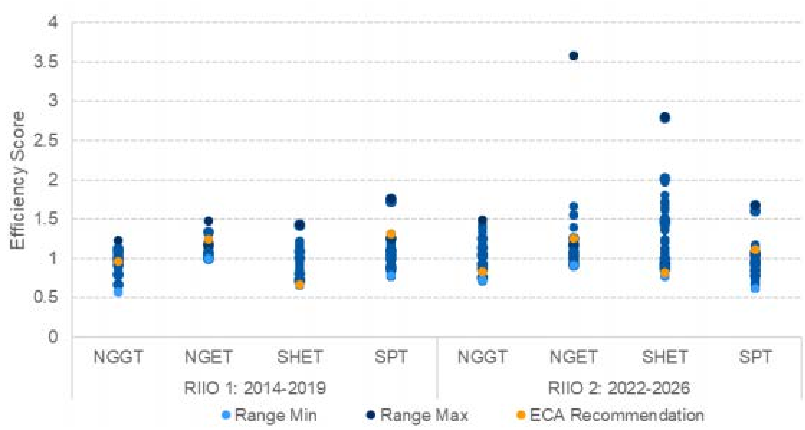
Ofgem's statistical models are not sufficiently reliable to assess efficient levels of indirect costs

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:

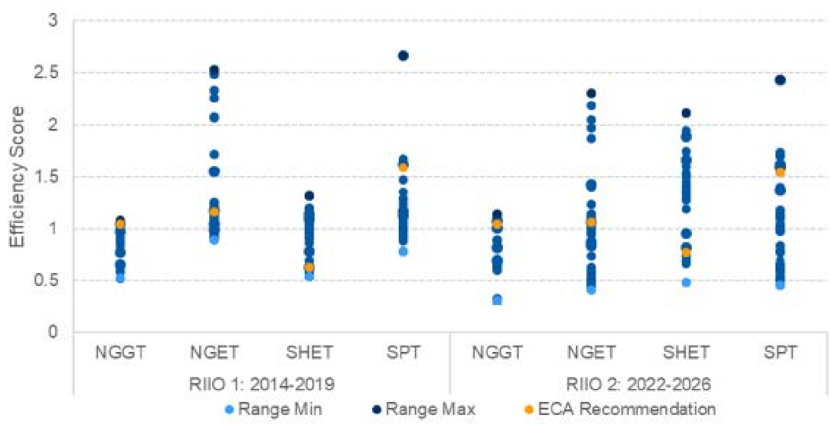
- Different ways of treating scale economies;
- Alternative cost drivers and combinations of cost drivers;
- And alternative model forms.

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.

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



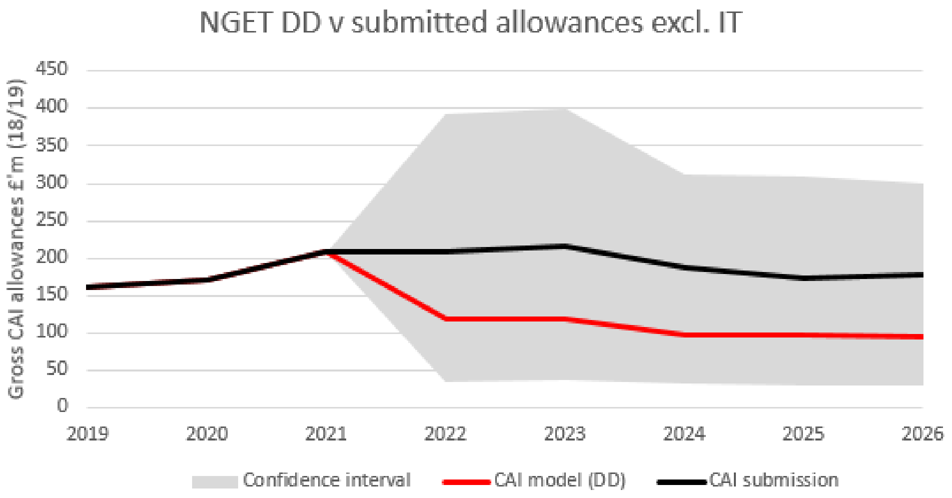
Source: NERA analysis.

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 NGET, CAI efficiency scores could be between 0.91 and 3.58, and BSC efficiency scores between 0.41 and 2.30. 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.

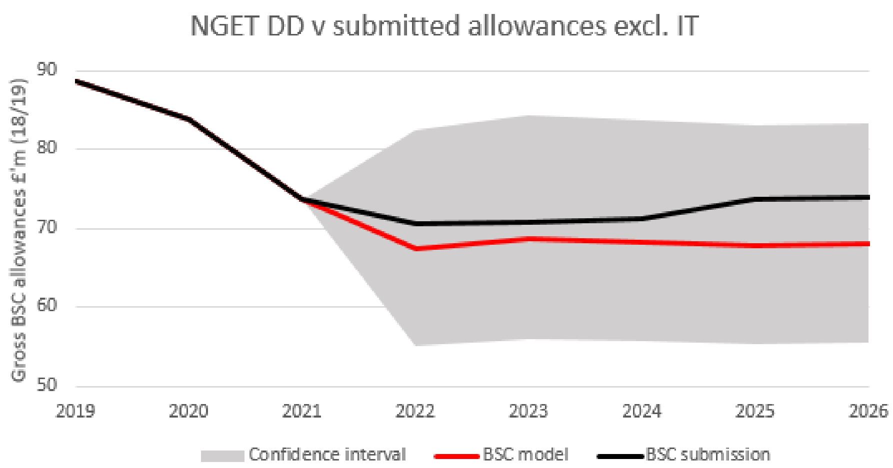
Our RIIO-2 submission for CAI and BSC costs fall within the efficient range of Ofgem's preferred models

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 charts show, 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.

NGET CAI RIIO-1 and RIIO-2 forecast costs and Ofgem modelled CAI costs and confidence interval



NGET BSC RIIO-1 and RIIO-2 forecast costs and Ofgem modelled CAI costs and confidence interval



Should Ofgem continue to place weight on ECA's preferred models, despite the evidence presented here and in NERA's report on inappropriate pooling of networks, model misspecification and sensitivity to modelling choices, our analysis demonstrates that their preferred models cannot be used to reject our business plan as being inefficient. Considered alongside the 17% efficiency relative to historic 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 have not sought evidence from NGET 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 11 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 14th February. 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 recommendation given by ECA 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 until 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 the publication of the draft determination. 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 operational costs

We agree with Ofgem's decision to allow our IT & telecoms in line with Atkins' assessment. 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'. NGET 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.

Vehicles and Transport

Please refer to NGET Q6 for CAI opex relating to fleet vehicles.

NGETQ16. Do you have any other comments on our proposed allowances for NGET?

Pensions

We agree with Ofgem's decision to fully fund pension admin and PPF levy costs in full and support Ofgem in retaining this decision in final determinations. These costs were previously treated as outside of totex due to our negligible ability to influence these costs.

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 T2 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.

Opex Escalator adjustment

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 16% of the direct costs of capital projects, consistent with our RIIO-1 average within our business plan 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 NGETQ15. 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 £50m 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' evidence indirect costs in addition to remedying the issues with baseline indirect cost funding that we raise earlier in this response.

NGETQ17 - Do you agree with our proposal to use a funding route more directly linked to actual engineering work on individual projects, and to provide a further route for funding through a re-opener window?

We do not agree that the proposed funding route for boundary capability investment is in the best interests of consumers. Our response to this question sets out: (1) our proposal and the DD, (2) our views on the DD, (3) developments since DD and (4) detail on how we developed our ex-ante UCA proposal.

We note there is a related question in the ET Annex, *ETQ13. Do you agree with our proposed scope of, associated eligibility criteria for, and timing of the submission window under the MSIP re-opener.* We cross reference responses where relevant.

1. Our proposal and the Draft Determination

We proposed an automatic ex-ante unit cost allowance uncertainty mechanism to manage the likely changes in wider network reinforcement needs that are expected to emerge during T2. This mechanism was designed around the understood principals of RIIO and ex-ante regulation and sought to improve on the performance failings of the T1 mechanisms. These failings have occurred as a result of deficiencies in the mechanism – (i) that it was not sufficiently granular to account for the range of potential solutions to delivering boundary capability and (ii) that the MW output a given solution delivers can be volatile. The table below sets out the T1 learnings and countermeasures proposed to ensure a better outcome for T2.

T1 learning	T1 deficiency	T2 countermeasure
	Mechanism covers all projects up to £500m	Mechanism restricted to projects <£100m
Insufficiently granular to cover range of solutions	UCA calculated on very small input dataset of handful of projects, specific to the solutions anticipated for each boundary	UCA based on all known solutions, calculated on an input dataset of 77 projects comprising 12 solution types
	Simple UCA based on £ per MW relationship for all projects	More granular UCA split into route and non-route solutions and using a combination of £ per MW and £ per km relationships depending on key cost drivers
MW output delivered can be volatile	Linear £/MW relationship exacerbates volatility	Non-linear £/ln(MW) relationship significantly dampens volatility and naturally caps allowances

Our view is that an agile ex-ante uncertainty mechanism is vital to ensure we can deliver the network reinforcements recommended by the ESO's annual Network Options Assessment (NOA) process and are incentivised to investigate and deliver innovative solutions at pace in this area. We describe the issues with the T1 mechanism, the rigorous process we followed in developing our proposals and an assessment of their performance against the T1 model and different possible T2 approaches in section 4 of our response to this question.

Ofgem have rejected our automatic ex-ante unit cost allowance proposal and instead propose that allowance adjustments for boundary capability projects are made through a combination of the Medium Size Investment Project (MSIP) re-opener and an ex-post true up at RIIO-2 close-out against PCDs that include both Primary and Secondary Deliverables. The Primary Deliverable is proposed as MW of boundary capability, whilst the Secondary Deliverable references detailed inputs specified in the Engineering Justification Paper for each project.

MSIP for boundary capability has a minimum threshold of £25m and a single re-opener window in January 2024.

Our views on the draft determination

Funding cannot be linked more directly to engineering work without ex-post checks that undermine efficiency and innovation incentives, which is not in consumers' interests. The Draft Determination approach to dealing with uncertainty in boundary capability reinforcements in the T2 period is entirely focussed on ensuring that allowances match costs as closely as possible at the expense of much larger consumer benefits. It does so unnecessarily as it has not fully considered the information we have provided to support a more agile, ex-ante approach or how this might be improved to optimise consumer benefits.

The proposal in the Draft Determination is detrimental to consumers because (i) it completely undermines all incentives to find efficiencies and innovate – increasing TO network costs, (ii) introduces delays in setting allowances and leaves funding gaps that will delay projects – increasing ESO operating costs (i.e. constraint costs) and delaying new customer connections and (iii) disproportionately increases administrative burden through a poorly designed and cumbersome reopener process that increases overall costs. We believe an automatic ex-ante approach can be designed in a manner that provides sufficient confidence in its cost-allowance performance so that the aforementioned consumer benefits can be maintained.

i. Undermining incentives to find efficiencies and innovate that will increase network costs

The proposal to move away from an ex-ante, output based approach to funding boundary capability projects, in favour of PCDs that explicitly reference the detailed inputs to be used in an ex-post adjustment of allowances will completely remove all incentives to find efficiencies and innovate in the delivery of outputs.

The CMA, in para 6.217 of its final determination of the case of SONI Limited vs. Northern Ireland Authority for Utility Regulation confirms this view when it notes that, "….*Any regulatory framework that involves an ex-post evaluation of costs may have similar asymmetric risk properties: the most a company can recover is its actual expenditure, but it faces a risk that some of its expenditure may be considered inefficient and it may not recover this portion of its expenditure*"

This applies both to big innovations that use new technology, such as our world first deployment of SmartWires at transmission voltage, and to standard consideration of alternative solutions using existing technology that reduces costs (e.g. hotwiring vs. reconductoring). As a result, consumers will lose the benefit of lower network costs and, in some cases, an earlier reduction in system operation costs when solutions with shorter lead times can be deployed.

We were the only TO with an ex-ante UCA for boundary capability in T1 and we are also the only TO to deliver the SmartWires solution (or any other innovative boundary reinforcement technology). This innovative solution will not only deliver consumer benefits of reduced network costs and faster reduction of constraint costs in the T1 period but, once a proven solution, will deliver benefits far into the future. Innovation such as this entails risk of failure. For a regulated network company, it only makes sense to take a risk investing in the development and deployment of innovative technology when the potential rewards are clear, through allowances that have been set up-front. The asymmetric risk properties of an ex-post approach are not conducive to this.

The incentive not to deploy standard alternative solutions using existing technology in order to mitigate the uncertainty of an ex-post true up is particularly concerning. We are constantly submitting different solutions to network requirements into the NOA process for assessment against boundary requirements (152 options for 19 boundaries in 19/20). Consumers benefit from this because the optimal solution will ultimately get delivered against changing network requirements. However, in a world where any difference between the solution set out in the PCD Secondary Deliverable and that ultimately delivered results in an ex-post true-up, there is a strong incentive to reduce the number of options and continue putting the same solution into the NOA process in order to mitigate the associated allowance risk.

The Draft Determination indicates there was a lack of data to assess our proposal

In para.4.11 of the NGET Annex the Draft Determination states that, "*NGET explained that its proposal was supported by statistical analysis on a large number of combinations of different technical options to deliver boundary capability. It has not provided Ofgem with detail of these technical options.*"

As set out above, the input dataset for our UCA development was based on 77 projects in total, spread across the following categories of boundary capability solution:

Non-route – 41 projects

Boundary capability solutions	Number of projects
Power Controller	11
Reactive Compensation	21
Substation	1
Transformer	7
Operational (switching)	1

Route – 36 projects

Boundary capability solutions	Number of projects
Cable Replacement	2
Hotwiring	8
New Circuit(s)	1
Reconductor	21
Turn-in	2
Voltage Uprating	1
Operational (advanced rating)	1

We believe this is representative of a large number of combinations of different technical options. As part of bilateral engagement on uncertainty mechanisms with Ofgem in October of 2019 and as part of our business plan submission, we provided three detailed Excel workbooks containing all our input data and assumptions, regressions for the six models we have considered and the T1 UCA for comparison and Monte Carlo analysis for each, as below.

<table>
<tr><th>Overview of workbooks provided</th><th>Contents of Dataset workbook</th></tr>
<tr><td>
Dataset of representative reinforcements for T2.xls
(Raw data, contents and sources, assumptions, outliers)

9 annotated worksheets + guidance
Calculation of UCAs with 6 regression models and T1 method.xls
(Raw data, OLS conditions, regressions for models A – F + T1 method, bootstrapping)

13 annotated worksheets + guidance; linked to explanatory slides
Monte Carlo analysis on cost distribution and model performance.xls
(Raw data, cost-allowance cals, monte-carlo sim. and results for each model)

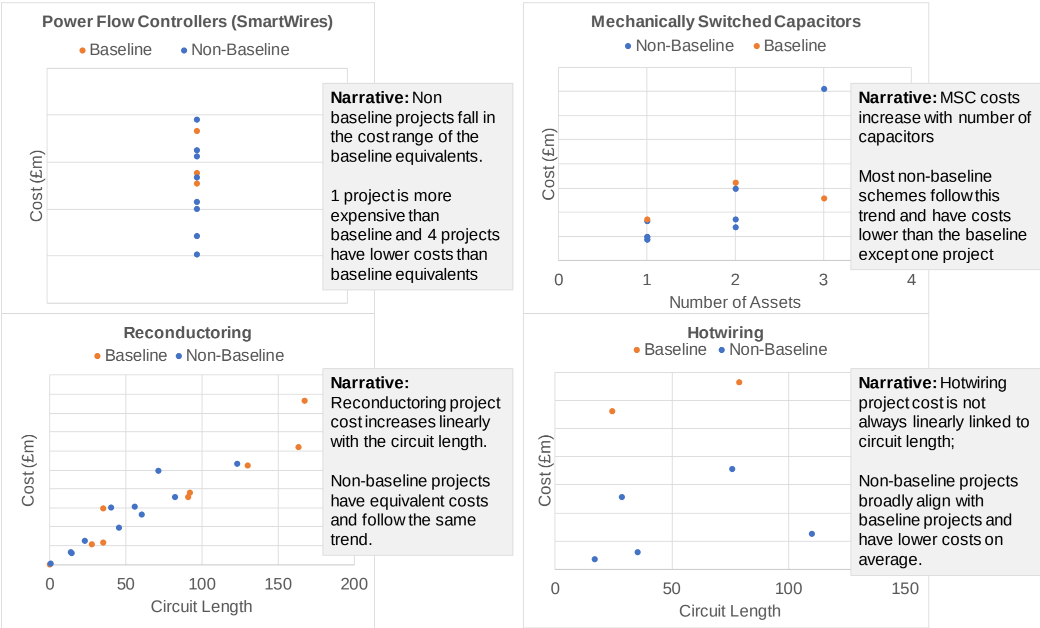
13 annotated worksheets + guidance; linked to explanatory slides
</td><td>
Raw data:
☐ NOA code
☐ Data source
☐ Project description
☐ Project type (route / non-route)
☐ Route length (km)
☐ Project cost (£m)
☐ Optimal delivery date (for each FES scenario)
☐ MW boundary capacity delivered
Other worksheets:
☐ Cable multipliers (unit cost ratios)
☐ Average circuit lengths
☐ Cable route lengths
☐ Inflation Adjustment
☐ Outliers
</td></tr>
</table>

In para.4.11 of the NGET Annex the Draft Determination states that, "*based on the limited information provided by NGET, we have not been able to scrutinise the range of technical solutions modelled and assess how well they represent efficient projects that could materialise in RIIO-ET2 and their potential impact on boundary capability. We are therefore not convinced that NGET's proposed volume drivers would address relevant uncertainty with fair allocation of risks and rewards in the interest of consumers.*

The data provided as part of our business plan submission provides the impact on boundary capability for each of the 77 projects used in our dataset. We also double checked our boundary capability impacts with the ESO before submission to Ofgem.

[redacted]

Whilst we were not able to fully populate the 'uncertain schemes' business plan data table in the time allowed during the Supplementary Questions process, we did provide Ofgem with analysis comparing each of the project types in our input dataset that were not in our baseline plan (52 projects in total) to those that were in our baseline plan (25 projects in total) and this was accompanied by detailed asset breakdowns in the business plan data table format. A further 26 projects from the dataset were of a solution type comparable to those in the baseline, allowing for some assessment of whether 51 of the 77 input projects represented efficient projects that could materialise in the T2 period as replicated below.



We have now also provided a fully populated 'uncertain schemes' table for boundary capability projects and further input data in the form of historic projects delivered in the T1 period to Ofgem. We would welcome the opportunity to work with Ofgem to further develop our proposal.

Ofgem should work with us to establish a robust ex-ante mechanism, avoiding the need for ex-post true ups that undermine incentives to reduce costs and deliver innovative solutions at pace.

The DD approach to funding projects that deliver beyond the T2 period (e.g. the first few years of T3) also misses an opportunity to incentivise efficiency because of the use of ex-post true ups. A version of the T1+2 approach used in T1 to set allowances for this expenditure, modified to be based on actual outputs rather than a forecast, should be adopted to maintain the incentive and to ensure that load-related projects are not simply delayed into the T3 period to access funding.

Ofgem should adopt an approach to projects delivering beyond T2 that provides appropriate funding and maintains an ex-ante efficiency incentive; a modified version of the T1+2 approach can achieve this.

ii. Introduces delays in setting allowances and leaves funding gaps

Each year when the NOA makes its recommendations there is churn in the projects that are indicated to proceed as both network requirements and solution options available change. This churn is valuable for consumers as it ensures the optimal solution is delivered once the need is clear. The Draft Determination proposal of a single re-opener window in January 2024 is not commensurate with the annual cadence of the NOA process. We provide our summary views, below, and have also responded this proposal in more detail through ETQ13.

A hypothetical new project that is given a proceed signal in 2021 would have to wait almost three years for funding certainty until an MSIP decision is made towards the end of 2024. Some solutions, such as SmartWires, can deliver consumer benefits within 18 months of receiving a NOA proceed signal.

Network companies will be reluctant to commit consumer money to investments in advance of some certainty of allowances and the only way to mitigate this is to revisit project programmes, which will have the impact of delaying projects by up to 3 years, or to minimise the range of options put forward to reduce churn. The opportunity cost for consumers of missed constraint cost benefits over this period could easily amount to £100m, whilst the cost of the SmartWires solution, although varied depending on how it is deployed, is typically in the £[redacted]m range.

An automatic ex-ante UCA approach provides certainty of allowances from the start of the price control and would therefore resolve this issue. At a minimum, if Ofgem forego the consumer benefits of innovation and stick with the proposed re-opener approach for the T2 period, an annual re-opener window would be required to align with the NOA. Nevertheless, even if Ofgem adopt an annual re-opener, this would introduce delays into projects to accommodate the submission, cost assessment and decision process, particularly given the volume of assessments that will be required each year (see iii. below)

Additionally, it is difficult to see how an annual re-opener approach can be made agile enough (likely needing to forego cost-assessment) and not require ex-post assessments, therefore undermining any drive to find efficiencies and innovation (see i. above). For this reason, an ex-ante UCA approach is the only way to avoid delays and the associated consequences for consumers).

Even if Ofgem move to an annual re-opener approach to align with NOA, it would not be possible to avoid ex-post assessments that undermine efficiency and innovation. We believe an ex-ante approach is the only way to avoid delays and associated consumer detriment.

The Draft Determination proposes a minimum threshold of £25m for the Medium Size Investment Project re-opener for boundary capability projects that have a NOA 'proceed' signal. We provide our summary views, below, and have also responded this proposal in more detail through ETQ13.

Our baseline plan for the T2 period contains 21 projects in total, with 17 that are <£25m. Therefore, over 80% of boundary capability investments planned in the T2 period would not be funded if they had to go through the Draft Determination proposal for dealing with uncertainty.

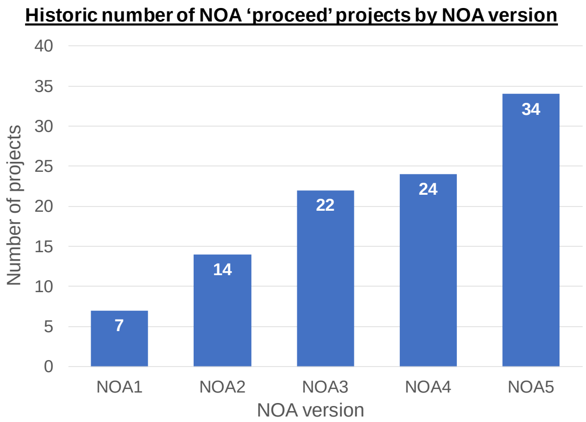
Projects such as hotwiring can cost as little as £1m, whilst some mechanically switched capacitor solutions can be delivered for around £10m. The cost of these projects is not directly related to the consumer benefits that they deliver, which will be many multiples of cost in almost all cases.

The proposed threshold, based on projects costing >£25m, is flawed because it will leave a massive funding gap for network companies, introduces a perverse incentive to increase project costs if they are below the threshold to access funding and, most importantly, does not consider the consumer value projects with a NOA proceed signal deliver which is by definition much higher than the cost. We will be unable to deliver these projects if this aspect of the Draft Determination is maintained.

Ofgem should abolish the concept of a threshold for boundary capability projects.

iii. Disproportionately increases regulatory burden and introduces perverse incentives

The need to go through a re-opener for all new solutions brought forward through NOA increases regulatory burden considerably. Between the NOA from 2019 and 2020 alone 10 new boundary capability projects were recommended to proceed (this is the net impact across all projects <£100m and >£100m and does not account for underlying gross movements in project status change). Whilst this level of change may very well represent a peak in the level of churn, project churn is not unique and likely to continue into T2, as shown across historic NOAs in the chart, below.



The scope for change in future NOAs is clearly high as NOA6, which will be published in 2021, is the first that will be based on net-zero compliant FES scenarios.

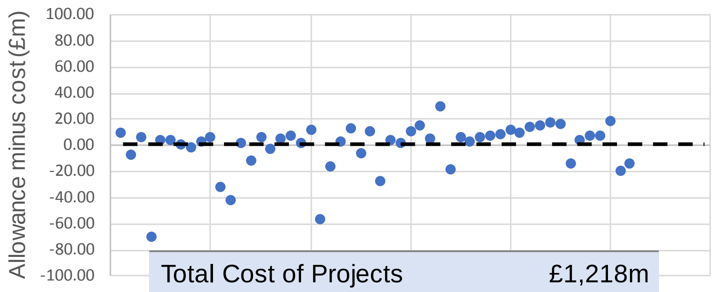
Detailed regulatory submissions and cost assessments for this many projects will take up considerable company and regulatory resources. This will, at best, increase administrative cost and, at worst, delay projects further.

An automatic, ex-ante UCA that provides sufficient confidence in cost-reflectivity is the only way to minimise administrative burden and risk of further delays to consumer benefits.

How our proposed automatic, ex-ante UCA could be further improved to increase confidence in cost-allowance performance.

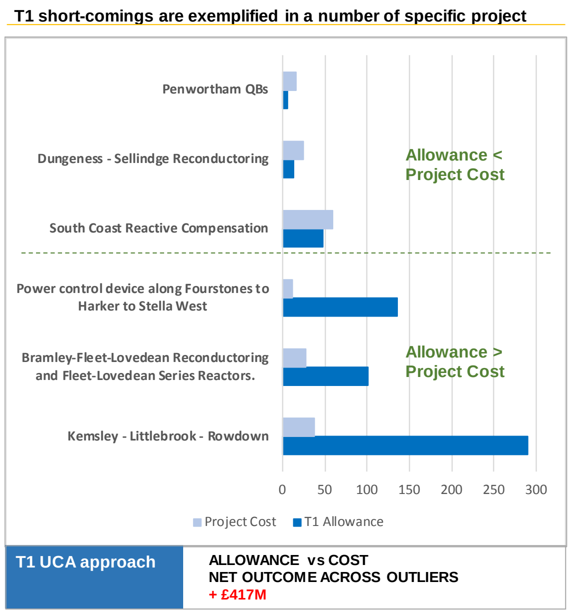
Since submitting our proposal in December we have been able to test the cost-allowance performance of our UCA against the new NOA, which was published in January of this year. The outcome of this analysis provides confidence that cost-allowance performance is strong against real-world uncertainty. Our proposed UCA was applied to all non-proceed projects from NOA5 (January 2020). There was a difference of only 0.8% between costs and allowances across this portfolio of projects.

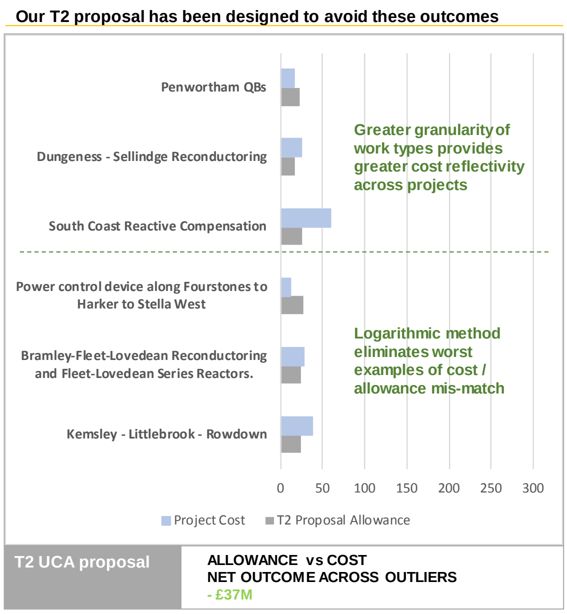
Cost-allowance performance of NGET UCA for non-proceed NOA 5 projects



Total Cost of Projects	£1,218m
Total UM Allowance	£1,227m
Difference	0.8%

The robustness of a given UCA design should be measured against its cost-allowance performance across a representative portfolio of projects that may need to be delivered in the T2 period, as above. However, we have also back-tested our proposal against projects that were the biggest outliers in the T1 period. The chart below shows that, on an individual project level, the proposed UCA performs better than that in place in T1. This indicates that the countermeasures we have implemented to address the main issues with the T1 mechanism performance have had a positive effect.





Despite the rigorous design framework used to design and test our proposal as well as application to real world NOA changes and T1 back-testing, the risk of a mismatch between allowances and costs cannot be completely removed. Changing network requirements and the range of solutions available for providing boundary capability will mean that there will always be some differences. Whilst these differences are highly likely to be small compared to the consumer benefits of an automatic, ex-ante volume driver (e.g. the standard deviation of the Monte Carlo results for our proposal is £68m, which is 13% of our proposed baseline allowance and a fraction of the consumer cost of a one year delay on larger projects), further protections can be put in place if deemed desirable.

We have assessed the consumer value areas of our proposal against the T1 approach, the Draft Determination proposal and other options that could provide this additional protection, as shown below.

Range of options available to manage uncertainty with different implications for consumers

				Ex-ante UCA with extra protections		
		T1 IWW mechanism	**T2 NGET proposal**	**Options on allowance timing, outputs, etc. (e.g. below)**		**T2 Ofgem DD**
Design criteria / consumer benefit	**Materiality**	Boundary specific £/MW UCA (average of 2/3 projects) Output = MW on a boundary	Solution specific £/logMW + £/km UCA (regression of 30+ projects per category) Output = MW non-route; MW + km route	Solution specific £/logMW + £/km UCA + re-opener OR other adjustment for outliers Output = MW non-route; MW + km route	Annual re-opener for all projects (no true-up and no threshold) Output = MW non-route; MW + km route	2024 re-opener; ex-post true-up Output = MW on a boundary + scope in EJP
Allowances reflective of cost of delivering output to protect companies and consumers		• UCA not sufficiently linked to primary cost drivers (not statistically robust)	• UCA statistically robust; mean ~ 0 and low std. dev. • Log function provides natural cap on allowances • Some tail risk for outliers	• UCA + re-opener for projects in tails of cost/allowance distribution OR portfolio level cap/collar adjustment mechanism (e.g. RAM)	• Frequency of re-opener aligns with annual NOA	• Minimum threshold (e.g. £25m) for boundary reinforcement
Clearly defined output reflecting range of potential solutions to protect companies and consumers		• Output definition not sufficiently granular (e.g. reconductoring vs. reactive compensation)	• Use of route vs. non-route + cable vs. OHL aligns with key cost drivers (e.g. linear vs. non-linear assets)	• Use of route vs. non-route + cable vs. OHL aligns with key cost drivers • Lock-in MW delivered when at first NOA proceed	• Use of route vs. non-route + cable vs. OHL aligns with key cost drivers (e.g. linear vs. non-linear assets) and negates need for ex-post	• Primary and secondary deliverables provide very granular outputs
Scope to innovate within a solution type to reduce cost to consumers		• Full scope to innovate within MW output definition	• Ex-ante allowance against route vs. non-route outputs incentivises within category innovation	• Ex-ante allowance against route vs. non-route outputs incentivises within category innovation	• Ex-ante route vs. non-route within category innovation (annual update dampens incentive)	• Ex-post assessment against secondary deliverables completely undermines innovation
Timing of allowance certainty relative to investment decision; avoiding potential delay to constraint benefits		• Full allowance certainty in advance of investment decision through ex-ante UCA	• Full allowance certainty in advance of investment decision through ex-ante UCA	• Allowance certainty for non-outliers in advance of investment decision for most projects through ex-ante UCA	• Annual allowance certainty through ex-ante re-opener (no ex-post true-up)	• No allowance certainty until either 2024 or T2 close-out through ex-post assessment
Proportionate administrative burden to minimise cost to consumers		• Allowance set at start of control; insufficient transparency through reporting	• Allowance set at start of control; more granular reporting requirements	• Additional process for outlier projects (could be re-opener as per generation and demand DD) OR automatic RAM on portfolio	• All non-baseline projects through re-opener	• All non-baseline projects >£25m through re-opener

A number of options have been identified that could provide additional confidence that allowances will sufficiently reflect anticipated efficient costs. We are exploring these options with Ofgem, as set out below.

3. Developments since the Draft Determination

Since Draft Determination we have been further exploring how an automatic ex-ante UCA approach could be made to provide sufficient confidence in cost-allowance performance with Ofgem and are progressing the following actions:

- ☐ Providing additional clarity on the UCA proposal in our business plan, where relevant
- ☐ Project input data-set updated to include historic projects delivered in the T1 period
- ☐ Asset-level detailed scope for input data provided through an update to the 'uncertain schemes' data table
- ☐ Design of an approach to freezing the MW capability delivered by a boundary reinforcement at the time of first NOA proceed to remove the impact of changing network conditions on allowances – increasing certainty
- ☐ Design of an extra-layer of protection on UCA performance in the form of a cap and collar on the percentage difference between allowances and costs across the portfolio of projects delivered in the T2 period

We welcome the opportunity to continue this development work to maximise the consumer benefits for this aspect of our business plan in the T2 period.

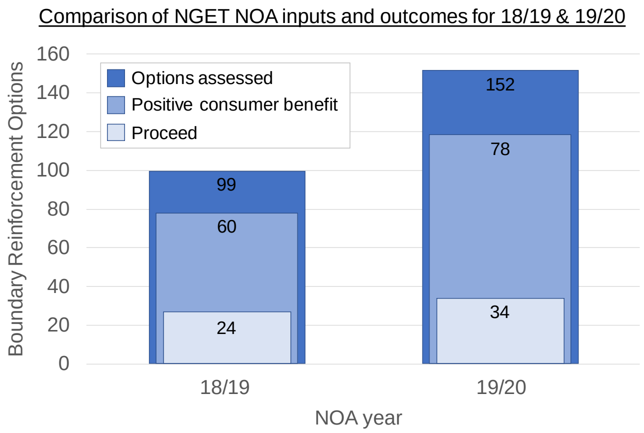
4. Detail of how we developed our ex-ante UCA proposal

Context

Our stakeholders have told us that they want us to enable the ongoing transition to the energy system of the future. Boundary capability reinforcements provide network capacity between different areas of the transmission system ensuring the use of low-carbon energy sources is maximised and minimising the cost of transporting power from where it is produced to where it is consumed. A single reinforcement can save consumers 10's to 100's of millions of pounds per annum in system operation costs compared to not investing.

We work in close collaboration with the ESO to provide inputs to the annual Network Options Assessment (NOA). The NOA uses Future Energy Scenarios to forecast future system boundary capability requirements. Transmission Owners submit reinforcement investment ***options*** to the ESO that can provide the additional future boundary capability required. The ESO then carries out regrets-based cost benefit analysis to determine which investment options are likely to provide ***positive consumer benefit*** and when these should be delivered; including a recommendation for which options TOs should ***proceed*** with immediately.

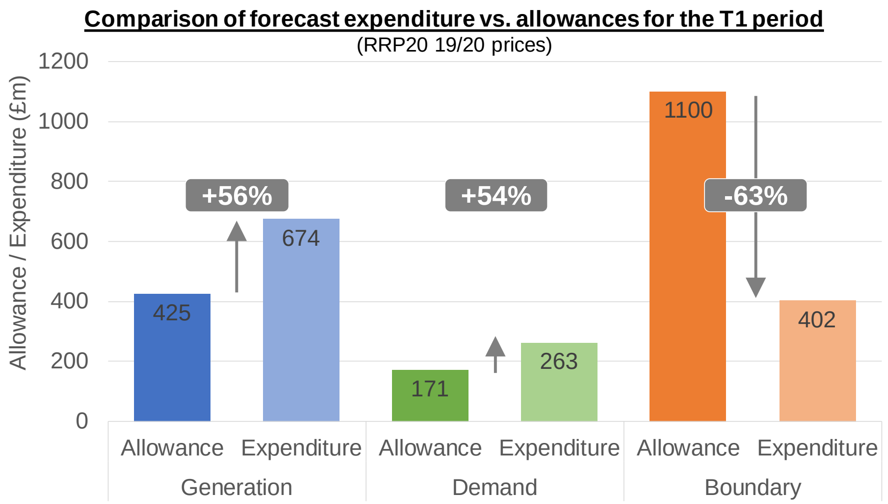
There are 29 key system boundaries across the transmission system in England & Wales. The chart, below, shows the number of options we submitted to the NOA process, how many provide consumer benefit and how many the ESO has recommended we proceed. In the last NOA we provided an average of over 5 options per boundary. The number of projects given a proceed signal increased by 40% from 24 to 34 between the 2018/19 and 2019/20 NOA iterations.



4.2. T1 approach and our T2 proposal

Volume drivers are used to deal with uncertainty for boundary capability reinforcements in the T1 period. The ex-ante unit cost allowances (UCAs) underlying this approach have allowed investments that benefit consumers to progress at pace, due to their automatic nature, and incentivised us to take risks and innovate in how boundary capability is delivered.

The mechanism covers all boundary projects up to £500m, which is the threshold for the Strategic Wider Works re-opener and provides a boundary specific, £/MW UCA. Our 2020 RRP submission forecasts an underspend against allowances of 63%. Allowance vs. expenditure performance across all volume drivers in the T1 period has been varied, as shown in the chart below.



Allowances vs. expenditure has deviated by an average of 57% across all the categories where volume drivers have applied. As noted in our response to the DD approach to uncertainty for generation and demand connections (ref. ETQ13B), a UCA based mechanism is a good starting point for the approach to uncertainty in the T2 period, despite this variability. A considered inspection of how these mechanisms have worked in T1 reveals improvements that can be made to significantly improve their cost vs. allowance performance for T2. The consumer benefits of being able to deliver at pace and the incentives to innovate outweigh the potential negative consequences for both network companies and consumers from inaccuracies in how well allowances match expected efficient expenditure.

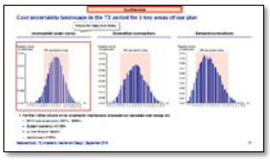
In embarking on the development of an approach to managing uncertainty for boundary capability projects in the T2 period, we have addressed the main deficiencies of the T1 mechanism – (i) that it was not sufficiently granular to account for the range of potential solutions to delivering boundary capability and (ii) that the MW output a given solution delivers can be volatile. The table below sets out the T1 learnings and countermeasures proposed to ensure a better outcome for T2.

T1 learning	T1 deficiency	T2 countermeasure
Insufficiently granular to cover range of solutions	Mechanism covers all projects up to £500m	Mechanism restricted to projects <£100m
	UCA calculated on very small input dataset of handful of projects, specific to the solutions anticipated for each boundary	UCA based on all known solutions, calculated on an input dataset of 77 projects comprising 12 solution types
	Simple UCA based on £ per MW relationship for all projects	More granular UCA split into route and non-route solutions and using a combination of £ per MW and £ per km relationships depending on key cost drivers
MW output delivered can be volatile	Linear £/MW relationship exacerbates volatility	Non-linear £/ln(MW) relationship significantly

		dampens volatility and naturally caps allowances

We implemented a 4-step framework for designing our T2 proposal based on learnings from the operation of the T1 approach, as shown below.

Quantification of uncertainty

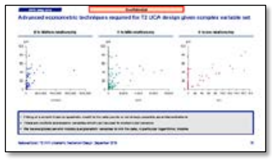


- Collate & benchmark data
- Model range of uncertainty
- Assess stakeholder needs

Assessment of Unit Cost Allowance designs

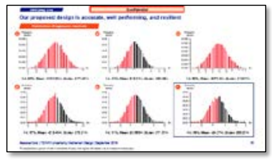
- Review T1 performance
- Assessment of cost drivers
- Long list potential designs

Design of accurate Unit Cost Allowance



- Regression modelling
- Econometric testing
- Short list potential designs

Test performance & resilience of designs



- Monte Carlo modelling
- Examine resilience
- Select preferred design

A long list of 7 candidate design options were filtered down to 3 by filtering out those deemed too rudimentary to address identified T1 learnings, where the input dataset would be too limited to be statistically robust, that were not compatible with the NOA process and where mechanism design could not be achieved in a transparent manner.

Of the 3 design options remaining, the 6 detailed designs set out below were fully developed and tested.

		Description of designs	Focus **regression model for each design**
1	**£/MW by boundary** *(modified vs. T1)*	**£/MW by boundary** – The average length (km) of existing conductor length across boundary is factored into the formula	**A** **Cost & MWkm with a linear relationship** **B** **Cost & MWkm with a natural log relationship**
2	**Single £/MW & £/km covering all boundaries**	**£/MW & £/km covering all projects** – MW is total capability increase across all affected boundaries – km is length of the reinforcement (*not average conductor length in opt 1*) – £/km only applies if it's a route project	**C** **Cost, MW & km with a linear relationship** **D** **Cost & MW with a natural log relationship; cost & km linear**
3	Separate UCA by category of project	**Examine UCA by asset groups, using learning from designs 1 & 2** **Different types of project groupings examined**	**E** **Route (km), route (non-km) and substation works** *(mix of linear & natural log relationships)* **F** **Route and non-route works** *(mix of linear & natural log relationships)*

27 different models examined across three designs

To determine which of these models represents the best unit cost allowance we used the following key metrics:

- ☐ **accuracy** – the best predictor of cost for each category (measured by fit; i.e. the explanatory power of the x variable),
- ☐ **performance** – design with closest mean zero regression residual (when examined over 10,000 simulations of delivering baseline capability), and

- **resilience** – narrow movement in the mean performance when examined by scenario (smallest standard deviation from the mean)

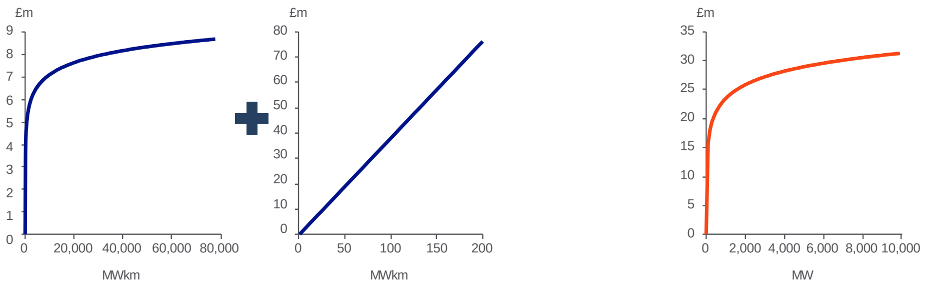
The table below summarises the performance of each design and model tested. It shows that model F, a separate UCA by category of project, was selected as best across the three criteria.

		Accuracy	Performance	Resilience
		Higher the better	*As close to zero the better*	*Lower the better*
Design 1	A	39%	-£464.09m	£174.57m
	B	54%	£12.44m	£88.32m
Design 2	C	62%	-£273.6m	£130.7m
	D	67%	-£12.46m	£73.31m
Design 3	E	61%	£0.565m	£71.51m
	Recommended F	69%	-£4.73m	£68.27m

Our proposal for T2, model F, is comprised of a UCA split into route (i.e. linear assets) and non-route (i.e. substation based) projects and uses a mix of linear and natural log relationships. Route km are expanded by cable multipliers (based on the ratio of cable to OHL costs) to account for the difference of cost between these solution types.

For route projects there are two components to calculating the UCA

For non-route projects there is one component to calculating the UCA



0.77 £m/ln(MWkm)

0.38 £m/km

3.4 £m/ln(MW)

MWkm = boundary capability increase x average circuit length of boundary

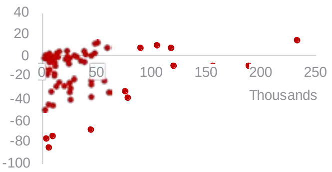
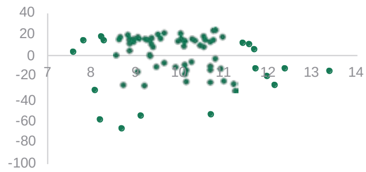
km = length of reinforcement

MW = boundary capability increase

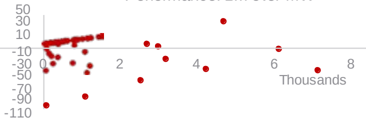
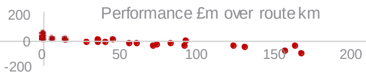
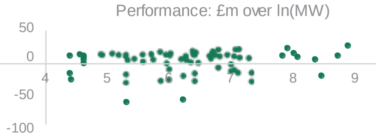
We include the detail underlying the summary assessment table, below. The three diagrams that follow detail our assessment of accuracy for the models within designs 1, 2 and 3. The final diagram is of the probability densities of allowance minus cost (aka the regression residual) across 10,000 scenarios of delivering baseline capability in the T2 period. These probability densities were used to measure performance and resilience.

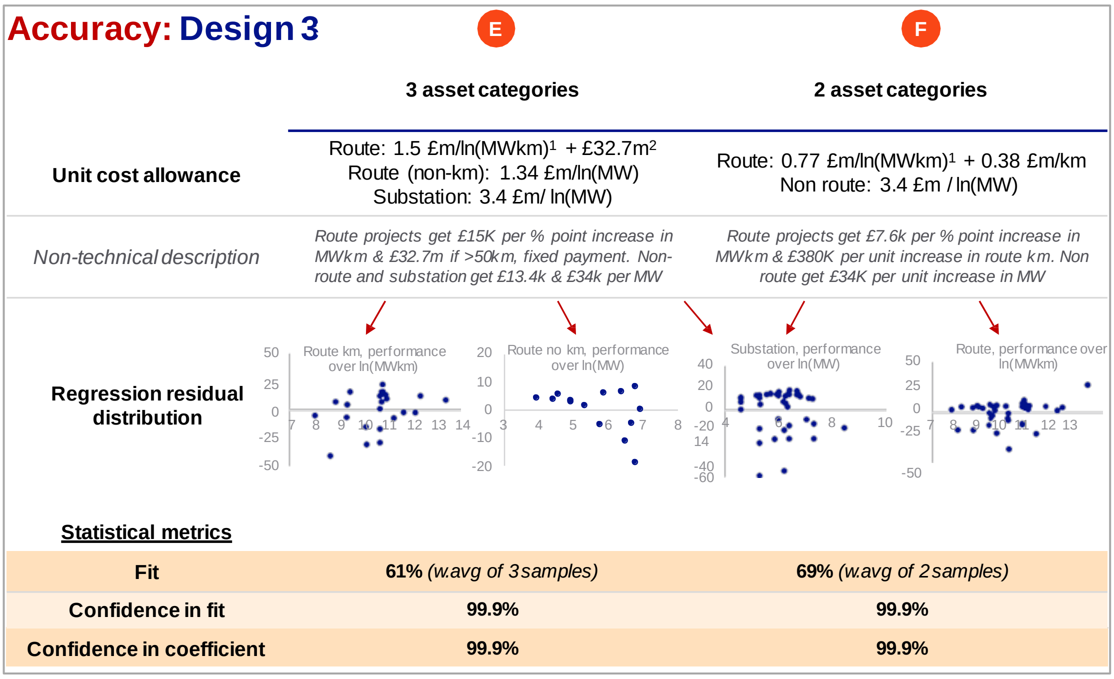
All data and models used to produce these diagrams was provided as part of our business plan submission.

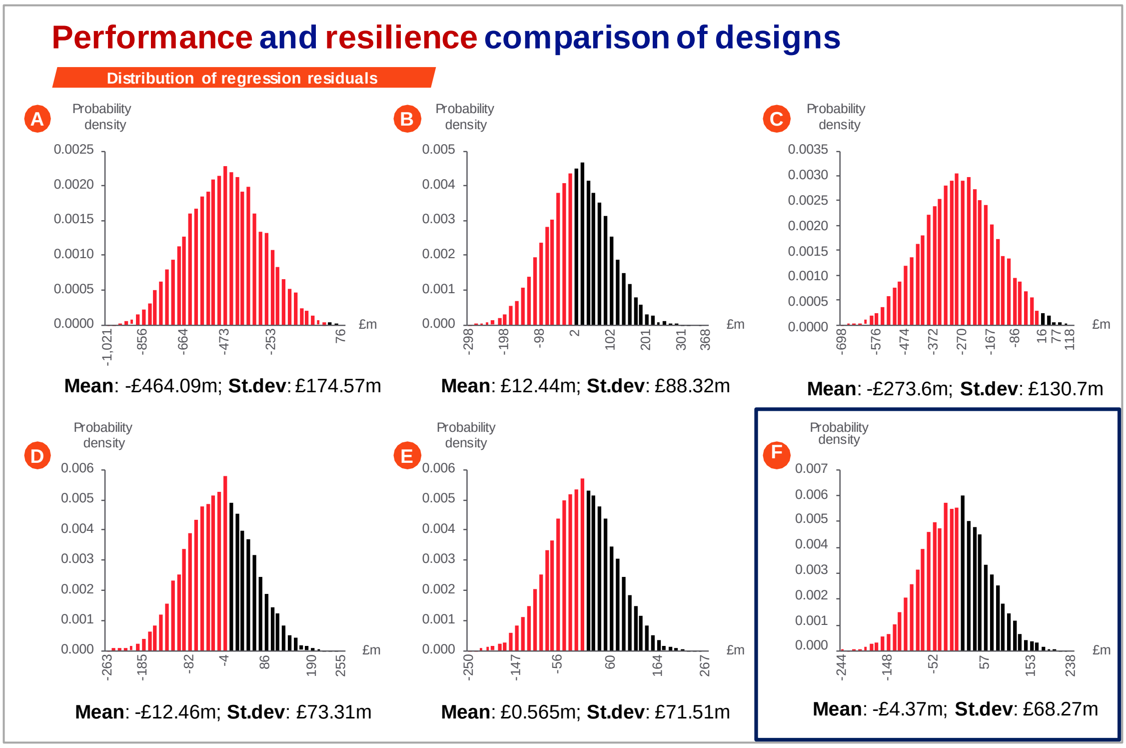
Accuracy: Design 1

	A Cost & MW with a linear relationship	B Cost & MW with a natural log relationship
Unit cost allowance	233 £/MWkm[1]	2.24 £m/ln(MWkm)[1]
Non-technical description	*Each unit increase in MWkm of a reinforcement will increase cost by £233*	*Each % point increase in MWkm of a reinforcement will increase cost by £22,400*
Regression residual distribution		
<u>Statistical metrics</u>		
Fit	**39%**	**54%**
Confidence in fit	**99.9%**	**99.9%**
Confidence in coefficient	**99.9%**	**99.9%**

Accuracy: Design 2

	C Cost, MW & km with a linear relationship	D Cost & MW with a natural log relationship; cost & km linear
Unit cost allowance	8.3 £k/MW & 370.7 £k/km	2.6 £m/ln(MW) & 281 £k/km
Non-technical description	*Each unit increase in MW and each unit increase in route km increases cost by £8.3k and £370.7k respectively*	*Each % point increase in MW and each unit increase in route km increases cost by £25.9k and £281.2k respectively*
Regression residual distribution		
<u>Statistical metrics</u>		
Fit	**62%**	**67%**
Confidence in fit	**99.9%**	**99.9%**
Confidence in coefficient	**99.9%**	**99.9%**





NGETQ18. Do you agree with our proposal to reject NGET's UIP UM?

We are disappointed that Ofgem have decided to reject our proposal for improving spaces for disadvantaged communities, especially given that this was proposed by an external stakeholder and also received strong qualitative support through our focus group research. We are unable to provide additional evidence of benefit at this stage as each proposal made would need to be judged socially and economically, individually and by a panel of stakeholders. We urge Ofgem to reconsider the position on this proposal.

NGETQ19. Do you agree with our proposal to provide a UIOLI allowance for offsetting capital carbon emissions?

We are comfortable with a 'use it or lose it allowance' for the capital carbon offsetting commitment. We do request however that we are able to finalise the allowance required for the financial year 2025/26 in line with the close of year RRP reporting timescales.

NGETQ20. Do you agree with the level of proposed NIA funding for NGET?

Whilst we are broadly comfortable with the headline figures, we do need clarity on the following aspects of the funding:

1. **Allowed internal spend:** In RIIO-T1, we could only spend a maximum of 25% of eligible NIA spend on our internal resources. In RIIO-T2, we request to increase the cap on allowed internal spend to 35% of eligible NIA spend. The additional requirements from a new benefit tracking system and an introduction of the audit process will require additional internal resources, which is on top of already admin heavy NIA governance process. Based on our T1 experience, we have also noticed that a closer engagement of our "subject matter experts" with the project partner improves the quality of research and increases the chances of project success and implementation thereafter.
2. **Eligible NIA funding:** We would like more information on what may be considered an eligible NIA spend as identified above, but also with some other aspects of spend that were allowed under NIA in T1, for example the membership fees of key research and innovation bodies, expenditure associated with stakeholder engagement, etc.
3. **Network licensee contribution towards NIA funding**: Confirmation regarding any proposed contribution from networks towards the overall NIA funding (such as the 10% included within RIIO-T1) and whether that contribution is on top of the proposed NIA funding noted in your draft determinations ?
4. **Deeside Centre for Innovation:** In our business plan we requested £30m for "Facilitating whole systems energy innovation". The key element to deliver in this area is to extend the Deeside Centre for Innovation developed as part of the NIC funded OSEAIT project and make it available to wider industry.

Considering new NIA funding framework, we request more clarity about if funding of the facility extension from NIA allowance could be eligible or not.

In the facility operating model submitted in October 2020 we stated that optimal model to allow access to the facility for all network licensees requires running cost covered for RIIO2 period. This funding period will allow time for the facility to become self-fundable after 2026. As estimated facility operational cost is approx. [redacted]year. The facility will be available to test a diverse portfolio of solutions with full range of technology readiness levels for all of the networks. We are confident that to realise full potential of the facility and deliver maximum value for consumers that the additional funding for operating the site should be added to the proposed NIA allowance.

Appendix 1 – List of Supporting Documents reference in our drat determination

Question Reference	Document Name
Q3	*NGET_NGETAnnex_Q3a update on an ODI on accelerating low-carbon connections*
Q3	*NGET_NGETAnnex_Q3b_TOs-ESO joint paper on reducing constraint costs*
Q4	*NGET_NGETAnnex_Q4_Estimate of SO:TO optimisation benefits in NGET's business plan*
Q5	*NGET_NGETAnnex_Q5_Extreme_Weather*
Q5	*NGET_NGETAnnex_Q5A_Extreme Weather_Summary of Tranche 1 site visits*
Q5	*NGET_NGETAnnex_Q5b_Extreme Weather_Chesterfield*
Q5	*NGET_NGETAnnex_Q5c_Extreme Weather_Newhouse*
Q5	*NGET_NGETAnnex_Q5d_Extreme Weather_Sheffield City*
Q7	*NGET_NGETAnnex_Q7_EGGB4_RIIO-ET2_CBA*
Q7	*NGET_NGETAnnex_Q7_Harker T2 SF6 loss abatement CBA*
Q7	*NGET_NGETAnnex_Q7_Lackenby T2 SF6 loss abatement CBA*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09_SF6_AGS*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-1 SF6 IDP_Lackenby 400kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-3 Stocksbridge 400kV SF6 Optioneering Report*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-3 SF6 IDP_Harker 400KV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-4 SF6 IDP Sizewell 400kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-5 SF6 IDP_Sellinge 400kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-6 SF6 IDP_Dinorwig 400kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-7 SF6 IDP_Northfleet East 400 kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-8 SF6 IDP_Neepsend 275kV*
Q7	*NGET_NGETAnnex_Q7_NGET A11.09-9 SF6 IDP_Palliatives*
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Q7	*NGET_NGETAnnex_Q7_NGET A11.09-14 SF6 IDP_Eaton Socon 400kV*

Q7	*NGET_NGETAnnex_Q7_NGET A11.09-15 SF6 IDP_Seabank 400kV*
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Q7	*NGET_NGETAnnex_Q7_NORT4_RIIO-ET2_CBA*
Q7	*NGET_NGETAnnex_Q7_Palliatives workbook*
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Q7	*NGET_NGETAnnex_Q7_SF6 Abatement - IDP Costing Assumptions*
Q7	*NGET_NGETAnnex_Q7_SF6 Leakage Actuals + Forecast Data*
Q7	*NGET_NGETAnnex_Q7_Stocksbridge 400kV CBA Analysis*
Q8	*NGET_NGETAnnex_Q8_BPI Section Annex*
Q11 & Q12	*NGET_NGETAnnex_Q11_Q12_Confidential Response to Ofgems Network Capex Cost Assessment*
Q11 & Q12	*NGET_NGETAnnex_Q11_Q12_MottMacDonald – an External report critiquing Ofgems Cost Assessment Process - full confidential version for Ofgem*
Q12	*NGET_NGETAnnex_Q12_DNVGL Report*
Q13	*NGET_NGETAnnex_Q13_NGET_A14.07_ET IT Supp Evidence (x25)*
Q14	*NGET_NGETAnnex_Q14_Appendix 1 - Sub Other-Other TO Detailed Descriptions - Company Confidential*
Q14	*NGET_NGETAnnex_Q14_NGET_A9.10__Substation Other and Other TO equipment Supplementary Evidence*
Q14	*NGET_NGETAnnex_Q14_NGET_A14.17b_Network Operating Costs Supplementary Evidence*
Q14	*NGET_NGETAnnex_Q14_NOC IDP to BPDT mapping files Company Confidential*
Q14 & Q15	*NGET_NGETAnnex_Q14_Q15_ Technical report_Opex cost assessment_confidential*