

An aerial photograph of a lush green field, likely a cornfield, with a large metal power line tower and several high-voltage power lines running diagonally across the frame from the bottom left towards the top right. The text is overlaid on the left side of the image.

national**grid**

RIO-T3 ET Annex Document Response

National Grid Electricity Transmission

August 2025

ETQ1. Do you have any views on our proposed approach to which projects will be in scope of the CSNP-F ODI-F, especially projects submitted through the Load Re-opener?

We agree with an incentive focused on the delivery of major network projects.

We have provided our view on the CSNP-F proposals in the Draft Determination (DD). However, there is limited information on the scope, eligibility and methodology for setting CSNP ODI-F outputs to be able to form a final view on the suitability and investability of the CSNP-F ODI-F.

We appreciate Ofgem is continuing to develop the incentive and through working groups is involving stakeholders in the process, and we will continue to support the development process.

We have provided a proposed solution for the design of a CSNP-F incentive in the supporting document “NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives”.

We are concerned about the following aspects of Ofgem’s proposal:

- **The lack of clarity over the intended scope, eligibility and methodology for setting targets** makes it impossible to judge the incentive’s risk and reward balance at this stage. Based on the delivery timetables for new network capacity upgrades and the lack of information, we do not consider the incentive presents the significant T3 performance opportunity Ofgem is suggesting.
- **The use of NESO’s CSNP outputs as targets are not a good basis for incentivizing behaviour because they may not take into account the deliverability of projects.** They risk not working for consumers as well as presenting significant risks to TOs, and there is a lack of clarity on how target dates would be set. Outputs of NESO processes will be immature, with high uncertainty over delivery dates. It not clear whether ‘earliest in service dates’ – which ignore delivery risk – would be used. Further, NESO is not the appropriate body to assess deliverability, and Ofgem should not fetter its discretion by delegating its decision making to another body. By proposing to set ODI-F parameters for CNSP-F Outputs by direction solely based on NESO’s CNSP, Ofgem is acting in a manner inconsistent with its powers under s7(5) Electricity Act 1989. Licence modifications are required, as set out in more detail below.
- **The change control process is inadequate as it would not re-baseline the incentive in delay events**, and we lack confidence that it would be operated reasonably.
- **The application of licence obligations layers on further open-ended risk**, which is especially unreasonable as the Target Delivery Dates would be taken from a NESO process outside our control, and the lack of clarity over minimum availability standards also presents a risk to the fair operation of the incentive.

We have outlined our concerns on these issues in the responses to this question and to ETQ2, ETQ3, ETQ4 and ETQ5 below.

We also have concerns, as set out elsewhere in this response (see responses to ETQ25, ETQ26 and ETQ27), about:

- 1) the lack of a T3 equivalent to the ASTI Early Construction Funding (e.g. to cover Strategic Land Purchases); and
- 2) the extent of coverage for high value Early Enabling Works in Pre-Construction Funding. This funding is critical to enabling timely delivery and therefore critical to the efficient operation of any timely delivery incentive.

Whilst we recognise that some flexibility is necessary and decisions on eligibility will be taken during the price control, the lack of clarity over which projects will be in scope makes it impossible to judge the CSNP-F Delivery ODI-F incentive’s risk and reward balance at this stage.

We consider this presents a significant performance opportunity during RII0-ET3 period given the first CSNP will not be published by NESO until late 2027. Ofgem’s Draft Determinations outline a position that the maximum opportunity/risk of this incentive and the ASTI delivery incentive is +/- 100 bps on average per annum. We are unable to reconcile those based on known ASTI projects due for delivery in RII0-ET3 and expectations on what projects will be in scope of the CSNP-F delivery incentive.

Ofgem must as a matter of urgency provide an up to date view on the maximum opportunity/risk from these incentives and an explanation of what has been assumed in reaching this position. We believe it should apply in the T3 period to the outputs of the tCSNP2 Refresh.

Ofgem’s approach appears to rely on a ‘portfolio effect’, whereby the downside of any probabilistically undeliverable targets would be outweighed by the upside of less challenging target. Our understanding is that this ‘portfolio effect’ is

intended to acknowledge the interconnected nature of all CSNP-F Outputs, such that all CSNP-F Outputs should be subject to ODI-F delivery incentives regardless of their different dates for delivery. Whilst this 'portfolio effect' reflects the fact that the consumer benefit of delivery of the whole set of CSNP-F Outputs by a certain timeline is greater than sum of timely delivery of each individual CSNP-F Output, our understanding is that the 'portfolio effect' does not consist in setting an ex-ante target on what the final financial net off of rewards and penalties across all CSNP-F Outputs will be.

For the benefit of clarity, as per our concerns outlined below in the responses to ETQ2, ETQ3, ETQ4 and ETQ5, we do not believe that an ex-ante target on financial net off approach to the "portfolio effect" would be reasonable.

In the absence of a decision on what projects will be subject to the CSNP-F ODI and in advance of NESO's various analyses being completed, it is impossible to know whether there will be a meaningful portfolio for any given TO. Even if a portfolio does exist, it is impossible to be confident on whether there would be a fair financial balance of risk and reward without understanding the nature of that portfolio, which is again unknowable at this stage. It is possible that the mix of projects in any set of outputs added under the CSNP-F ODI-F would be skewed by a disproportionate number of 'urgent' schemes that would introduce unacceptable risk for TOs.

Given the ambiguity as to how the CSNP-F ODI-F proposed in the Draft Determinations is intended to operate, **Ofgem must clarify the meaning of its statement at paragraph 3.8 which states "We consider that, as CSNP-F Outputs are optimised as a portfolio (e.g. through the CSNP) we should incentivise them as such"**.

The table below sets out the areas where clarity is required:

<p>CSNP Outputs</p> <p>The DDs confirm that "all CSNP-F Outputs will have the CSNP-F ODI-F applied", regardless of delivery date and level of urgency. NESO's Optimal Delivery Date would be used as the Target Delivery Date (TDD) for these projects.</p>	<ul style="list-style-type: none"> • The CSNP will not be published until Q4 2027 so it is not possible to know the number, value and types of projects selected, or their level of urgency. • It is not clear whether all outputs of CSNP will become 'CSNP-F Outputs'. We assume that all CSNP 'delivery pipeline' recommended projects would be CSNP-F Outputs, but this is not explicitly stated in the DD. • Given that most CSNP outputs are likely to deliver beyond T3, it is unclear how CSNP-F can be considered by Ofgem as a source of potential T3 performance. • Assuming the 'earliest in service date' (EISD) is the target date for urgent schemes, it is impossible to judge in advance whether the risk/reward balance is fair to TOs and consumers without knowing the balance of 'urgent' to 'non-urgent' projects. • The CSNP process would not allow project-specific Quantitative Schedule Risk Assessment (QSRA) and therefore would rely on risk-adjustments through Reference Class Forecasting (RCF).
<p>tCSNP2/tCSNP2 Refresh</p> <p>Ofgem is "considering whether tCSNP2 and tCSNP2 Refresh projects are best progressed ... using the Load Re-opener or the CSNP-F Re-opener" and that "projects with a 'proceed' signal in the tCSNP2 Refresh" might be included.</p>	<ul style="list-style-type: none"> • We have some knowledge of what the potential tCSNP2 Refresh outputs might be from the NESO tCSNP2/Beyond 2030 outputs. However, it is not due to be published until 2026, and the need and optimal dates of these projects may change. • It is not clear whether the CSNP-F framework would apply to these projects, or whether the ODI-F would be applied and if the ODI-F were applied, how it would be calculated in terms of the TDD and incentive. • Again, assuming EISDs would be used as targets for tCSNP2 Refresh projects, it would be impossible to judge in advance whether the risk/reward balance is fair to TOs and consumers. • As with CSNP, the tCSNP2 Refresh process would not allow project-specific QSRA and therefore would rely on risk-adjustments through RCF, assuming inputs are mature enough.
<p>Other projects</p> <p>For projects that are not CSNP-F Outputs Ofgem will decide whether to apply the CSNP-F ODI-F on a case-by case basis, including those proposed by TOs in the Load Re-Opener. For projects without a NESO-recommended target date, Ofgem "would need to determine an</p>	<ul style="list-style-type: none"> • It is not clear what criteria would be applied in considering Load Re-opener projects. e.g. what is "strategically important" other than "required to enable key CSNP-F Outputs"? • As acknowledged by Ofgem, it is not clear how a robust TDD would be determined in the absence of an independently developed NESO date. • Further confusion is created by the positioning of the Delivery incentive in Stakeholder Summary material as being intended for CP30 projects, despite there being limited overlap with tCSNP2 and the DD stating that the Connections Capacity ODI-F (not the Delivery incentive) is focussed on enabling connections to achieve CP2030. • The DD is silent on whether Provisional ASTI projects would be eligible for the Delivery incentive and how target dates might be set, including the

appropriate Target Delivery Date (TDD) that is achievable and aligned with system requirements”.	<p>three recently exempted from competition by Ofgem (EGL5, WL2, LRN#).</p> <ul style="list-style-type: none"> • The DD appears to reserve the right to apply the ODI-F to other types of project than those in the Load Re-opener and tCSNP2/Refresh, which leaves an open-ended possibility that the Delivery incentive could apply to other project types not considered here.
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In our view, the incentive should only apply to categories of project where there is clear consumer value in timely delivery. We therefore believe it should apply in the RIIO-T3 period to the outputs of the tCSNP2 Refresh.

Ofgem’s approach of potentially applying the CSNP-F delivery incentive to projects that have not come from a NESO centralised planning process means that further uncertainty is added in attempting to assess the overall risk and reward balance of the price control framework.

To improve the ability to forecast which projects will be in scope and importantly ensure that the incentive is targeted to the delivery of consumer value, the Final Determinations must set out clear and transparent criteria that will be followed in selecting projects.

These criteria should be:

- **Consumer value:** The incentive should only apply where there is clear consumer value in accelerating the project relative to a focus on cost efficiency. This is a clearer position than Ofgem’s proposed position that “strategically important” projects are eligible as we cannot find a meaningful way of defining what strategically important means.
- **Maturity:** Projects must be sufficiently mature to allow us to undertake robust probabilistic assessment of delivery timelines. The CSNP process would not allow project-specific Quantitative Schedule Risk Assessment (QSRA) and therefore would rely on risk-adjustments through Reference Class Forecasting (RCF).
- **Availability of an assured target delivery date:** Ofgem and TOs will need to establish an approved method for setting the target delivery date in order to apply the incentive. A proposed method for setting target delivery dates is discussed further in our response to ETQ2.

Ofgem proposes that for non-CSNP projects (para. 3.14) the incentive will be introduced via licence modification but for CSNP projects it will be introduced by direction (para. 3.10). Ofgem states that it considers that the latter is appropriate because it will be in a position to set out the manner and circumstances under which the modification will be made. **We do not agree with such an approach and are unclear how Ofgem has satisfied itself that this is consistent with its powers.**

As Ofgem will be aware, Section 7(5)(b) of the Electricity Act 1989 (EA89) states that “*conditions included in a licence may contain provision for the conditions ...to be modified in such manner as may be specified in the conditions at such times and in such circumstances as may be so determined*”. The use of directions and the statutory interpretation of s7(5) was considered in detail by the CMA in its Final Determinations for the RIIO-2 Appeals.¹

Importantly, the required inputs to the ODI-F for CSNP-F Outputs which will enable TOs to meaningfully understand the impact of the modification will, as paragraph 3.10 acknowledges, be published by NESO (i.e. the ODD, project Totex and constraint costs). As a result, the manner of the licence modifications that are required to introduce the ODI-F for a CSNP-F output will not be able to determined from the condition itself or any document having equivalent status. Such an approach is not consistent with that endorsed by the CMA

As such, TOs are not in a position to understand the potential impact on them of a future modification and therefore not in a position meaningfully to appeal the condition to the CMA at the outset of the price control if necessary. As previously stated by the CMA in the *Energy Appeals 2021* (para 8.129), “*if the criteria defining the manner of the modification cannot be set out in the licence condition in any meaningful way, [Ofgem] has no power to proceed under section 7(5)(b) [EA89]*”. We therefore we consider it is not open to Ofgem to rely on s7(5) EA89 to propose to introduce a self-modification approach in this instance.

Ofgem must introduce any licence modifications for this incentive by statutory licence modification under s11A EA89 as is proposed under paragraph 3.14 for non-CSNP-F projects and not by direction as is currently proposed.

¹ As the CMA said at paragraph 8.126 of its Final Determination in the RIIO-2 Appeals: “We should add that, in order for the criteria to be sufficient to meet the requirements of section 7(5)(b), they must be contained in the licence condition itself, or in a document which has the status of a licence condition. This is clear in section 7(5)(b). It is in our view insufficient for the criteria to be contained in a subsidiary document, which (i) may or may not be published at the time of the adoption of the licence conditions themselves, and (ii) is subject to change by direction at any point during the price control period. In that case, licensees may have no effective ability to challenge the criteria in an appeal under section 11C of EA89.”

In our supporting document NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives, we provide full detail of the design of an incentive that meets our proposed objective.

Ofgem must engage with TOs and other stakeholders to finalise the incentives in advance of the Final Determination. We recommend using our proposal as the basis for the design of the incentive.

ETQ2. Do you agree with our proposed approaches to determining a TDD for CSNP-F Outputs and non-CSNP-F Outputs?

We do not agree with the proposed approaches to determining a TDD for outputs under this incentive as there is not clarity over the terminology in the proposals to make an assessment.

We appreciate Ofgem is continuing to develop the incentive and through working groups is involving stakeholders in the process, and we will continue to support the development process.

We have provided a proposed solution for the design of a CSNP-F incentive in the supporting document “NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives”, which Ofgem should use to inform the approach to setting a TDD.

There are inherent risks in delivering major infrastructure projects. Though we support Ofgem’s position of providing a date range in which a project can be delivered before an incentive penalty is incurred, there are significant outstanding concerns over the methodology for setting TDDs. Below, we have set out our understanding of Ofgem’s approach, alongside our views.

Optimal Delivery Date

The DD states that “*wherever possible*” the TDD will be aligned to NESO’s Optimal Delivery Date (ODD). However, Ofgem has since clarified (in the email to the TOs dated 14th August 2025) that the references to ODD – that is, the date by which delivery would be economically optimal, regardless of deliverability – in the DDs are incorrect. The intention is to use the “the recommended date from the CSNP”, known as the “Recommended Delivery Date” (RDD). We understand that the intention is that the TDD will be the RDD, which would be the later of:

- the Estimated Delivery Date (EDD) – that is, what is considered ‘deliverable’ by the TOs on a P50 basis; and
- the ODD – that is, what is considered by NESO to be economically optimal (regardless of deliverability).

We support this confirmation provided by Ofgem that the intention is not to set target delivery dates that are earlier than TO EDDs.

Ensuring that target dates are realistically deliverable by TOs is an essential core principle in ensuring a framework that balances risk between TOs and consumers fairly. For the avoidance of doubt, it would be unacceptable as a matter of regulatory principle to use optimal (ODD) dates as TDDs where they are earlier than the EDD as they would not be underpinned by a deliverability analysis, and therefore highly unlikely to be achievable by TOs.

‘Deliverable’ date and immaturity

During the TO discussion with Ofgem on 12 August, the terms ‘delivery date’, EDD and ‘earliest in service date’ (EISD) were used interchangeably.

Our understanding from NESO’s CSNP Draft Methodology is that the concept of EISDs will not feature in the CSNP process, being replaced by EDDs that are “risk-adjusted delivery dates” (p.137) based on “probability risk analysis at the 50th percentile” (p.126). However, our understanding is that Ofgem’s expectation is that ‘earliest’, rather than ‘risk adjusted’ may be set as the TDD for urgent projects (i.e. those where the required date is the same or earlier than the deliverable date). **Using deterministic EISDs rather than dates adjusted to take account of delivery risk would be unacceptable in principle as it would expose TOs to asymmetric risk.** The CSNP methodology has not yet been finalised and we still therefore consider that material risk to TOs remains as these dates may not adequately reflect deliverability risk.

Furthermore, while CSNP options are expected to reach sufficient maturity for informed decisions regarding progression into the CSNP delivery pipeline (NESO Level 2, following strategic optioneering), a material degree of uncertainty regarding potential delivery dates within CSNP outputs is inevitable. It will generally be possible to carry out some degree of Reference Class Forecasting (RCF) at this stage, but not project-specific Quantitative Schedule Risk Assessment (QSRA). It is important to recognise that, where delivery is ‘as soon as possible’ then project plans are much more likely to see delays (which arise due to both known and unknown risks) than accelerations (which will only reflect unknown opportunities). RCFs are the standard way of making such adjustments.

It is therefore unacceptable as a matter of regulatory principle to set dates using immature and deterministic (probabilistically unachievable) EISDs. This would systemically expose TOs rather than consumers to the risks created by inherent uncertainty in the CSNP options development process. For a given project, this uncertainty will diminish over time as project teams advance recommended options through project-specific activities such as surveys and consultations, which will result in more robust schedules, which could be used to set more realistic TDDs at a later point in time.

Ofgem must:

- **adopt an approach where any target date based on the outcome of a NESO network planning exercise is on the basis of risk analysis robust enough to ensure a fair balance between TOs and consumers, properly taking into account deliverability risk.**
- **set Target dates which are the later of 1) the risk-adjusted RCF P50 deliverable date (as verified by the Independent Technical Adviser) or 2) the recommended / optimal date (from the NESO process).**

The fairness of any such targets would also be dependent on the resolution of several other concerns, as laid out in this response, about:

- Adequate change control protection;
- Licence obligations;
- Minimum availability incentive; and
- Coverage for early spend commitments, such as strategic land purchase and Early Enabling Works.

NESO responsibilities

Whilst we agree that NESO is well placed to assess optimal delivery dates, NESO does not have the technical capability to assess the deliverability of projects to the standard necessary to set timely delivery incentives.

Historically, TOs have provided almost all information on deliverability to NESO, particularly for onshore assets, but this is unlikely to be acceptable in the context of incentive setting. In this context, and whilst Ofgem may ask NESO to develop this capability, it is important that Ofgem, also develops its own plans to assess the success of any such efforts and the realism of TOs' own views.

Ofgem should not fetter its discretion by delegating its decision making to another body. This is especially the case when Ofgem is required to give consideration to criteria such as investability (which is relevant to potential negative skew of the delivery ODI-F regime based on dates chosen), which NESO does not have to consider in the same manner.

Ofgem must therefore apply its own scrutiny to the dates that come out of the CSNP process and commit to consulting with TOs on the dates to be used as targets, rather than simply taking the output of the CSNP process.

Ofgem must apply its own scrutiny to assess and verify the inputs provided by the TOs, rather than relying on NESO analysis. This should be supported by the proposed Independent Technical Adviser.

Portfolio effect

The issues described above are particularly important if Ofgem were to rely on a 'portfolio effect' approach whereby the financial downside of any probabilistically undeliverable TDDs (where the required date is earlier than the risk-adjusted deliverable date) would be outweighed by the financial upside of less challenging TDDs for 'less urgent' projects (where the required date is later than the deliverable date), with an ex-ante target of net off of financial reward and penalties across the whole suite of CSNP-F Outputs.

As covered in our response to ETQ1, it is not possible to make a judgement on whether there would be a financial balance of risk and reward from this proposed portfolio effect, or even to have confidence there will be a portfolio. It is possible that the mix of projects in any set of outputs added under the CSNP-F ODI-F would be skewed by a disproportionate number of 'urgent' schemes that would introduce unacceptable risk for TOs.

Given the existing known delays to NESO's system planning functions, we expect further delays and so we expect that many projects will be triggered later than is optimal and so the proposed CSNP-F ODI-F may produce a significant, but not quantifiable, expected net negative outcome for TOs.

Ofgem must set TDDs on a project by project basis and not rely on a portfolio effect as part of calibrating the incentive.

Other projects

For other types of projects that could have a CSNP-F delivery incentive attached, a methodology will need to be established for setting the target delivery dates. These methodologies must ensure that risk is managed on a project-by-project basis, given it cannot be assessed across a portfolio and we welcome Ofgem's acknowledgement in paragraph 3.14 that this will be consulted on.

Ofgem must engage with TOs to develop this methodology before Final Determinations so TOs can robustly assess the risk of the price control framework. The methodology should be based on best practice from elsewhere in Government and industry, and the principles outlined above about deliverability and risk adjustment.

As discussed above, best practice is to use risk adjustments to initial plans in order to plan for and target a realistic date, with experience elsewhere showing that significant cost and risk comes from targeting unrealistic dates.

Interaction with Project Assessment stage

The CSNP-F ODI-F section of the Draft Determinations, and subsequent discussions, appear to be predicated on the concept of setting targets dates following the publication of CSNP. However, this approach must then be read in the light of the description of the later Project Assessment stage in the CSNP-F Reopener section (para. 4.116), which states the following:

"Once the TO has full detail on the project design and cost they can provide a submission for a Project Assessment Decision. Approval of a project through this process will result in an update to the CSNP-F Output definition and delivery date, as well as including an allowance to reflect the approved project cost.

Paras. 4.117 and 4.118 then go on to say that "the TO may apply for an update to the CSNP-F Output definition, cost, or delivery date through the COAE process, if there has been a relevant COAE (e.g. an extreme weather event)" and Para. 4.118 that, "given the importance of delivery of these projects, we propose to include an LO for delivery of the CSNP-F Outputs on the delivery date included in the licence. This delivery date will be set as the ODD as determined by the NESO unless amended in the licence, such as by COAE".

It is therefore difficult to tell whether the intention here is that:

- ODI-F TDDs set earlier in the process will be reviewed in the Project Assessment process (and therefore not fixed as part of a portfolio) or whether it is the output delivery date but not the TDD that will change under such a process; and
- Any changes to ODI-F TDDs will only result from COAE or whether it is the output delivery date but not the TDD that will change under such a process;

Ofgem must clarify the proposed policy intention here to enable TOs to clearly understand how and when CSNP-F Output delivery dates and CSNP-F TDDs will be set and how/ when each such dates may be changed under the proposed CSNP-F framework.

We have set out our concerns on Licence Obligations separately (in our response to ETQ5), but the specific meaning of this section relative to the CSNP-F ODI-F section should be clarified.

ETQ3. Do you agree with our proposed inclusion of a minimum availability standard in the CSNP-F ODI-F?

We do not agree with the proposed 24-month minimum availability standard of 93% circuit availability because a single standard does not reflect the variation across projects.

We recognise the importance of ensuring availability of new infrastructure and support the principle of a minimum standard to confirm delivery of new build assets. However, we cannot support the standard Ofgem has proposed, for which it has failed to provide any evidence or justification.

We consider that a set minimum availability standard cannot apply to all projects, and variation across projects will be necessary. This has been recognised within the existing ASTI regime where the minimum circuit availability standard is specified for an individual project at the Project Assessment decision stage. We see no reason why this approach should not apply in the context of the CSNP-F ODI-F. Different assets have a different likelihood of failure and repair time.

Ofgem must instead work with TOs to determine a framework that would be applied when setting the minimum availability standard for each project where the CSNP-F delivery incentive applies and which could be equally applicable to ASTI.

We believe that a sensible and collaborative approach between Ofgem and the TOs would include the following:

- Shape and design how Ofgem will determine an Availability Standard across ASTI and CSNP Projects;
- Establish a framework that Ofgem will determine any Minimum Availability Standard (MAS) by – ensuring visibility and certainty, as well as ensuring there is appropriate scope and exclusions
- Align with Ofgem on how the MAS should be decided and applied into the licence as part of the ASTI decision making process (and future CSNP process)

We believe there are four elements that could constitute this framework:

1. Definitions:
 - a. Definitions already exist within publications from External and Industry Bodies – for example CIGRE, TB 697, CIGRE TB 852 and BS EN 61975
2. Scope:
 - a. We will need to articulate the assets within the scope of a minimum availability standard. We expect this standard to apply to circuits as opposed to individual assets.
 - b. The testing and repairs regime will need to be taken into account.
3. Single combined availability target:
 - a. Establish information relied on to establish a single, combined availability
 - b. Ofgem must have regard to challenges with asset classes measurements
4. Exceptions and inclusions will likely need to include:
 - a. An exemption for exceptional events and, for nonexceptional events
 - b. Matters outside the licensee's reasonable control
 - c. Matters not attributable to any error or failure on the licensee's part

ETQ4. Do you agree with our proposed approach to Delay Events in the CSNP- F ODI-F?

We agree that delay events should be a feature of the incentive design and used to address delays that are outside of the TO's reasonable control, and which are not attributable to an "error or failure on the licensee's part". However, we do not agree with Ofgem's position on how they will operate.

The following table summarises the areas of Delay Events with which we do not agree or require further clarity on to form our view. It also sets out the changes Ofgem must make in advance of the Final Determinations.

Aspects of Ofgem's proposal for Delay Events for CSNP-F ODI-F we do not agree with or are unclear:

- We disagree with the approach that Delay Events result in penalty dates shifting back but reward dates not being adjusted accordingly.
- There is a lack of clarity on Delay Event definitions including: what triggers a delay event and what is judged as an "error or failure on the licensee's part".
- We are unclear how Ofgem will calculate the days of delays associated with a Delay Event
- We disagree with Ofgem's position to not include supply chain constraints as a Delay Event on the basis that the Advanced Procurement Mechanism (APM) will safeguard against supply chain delays.
- We believe the operation of Delay Events for the CSNP-F ODI-F could be improved through application of the Independent Technical Advisor (ITA) validating Delay Event risks and providing views on incentives
- It is unclear how assessment and remediation of implications of Delay Events will be calculated for investments at portfolio wide level.

Further detail and explanation of this position is as follows:

To prevent asymmetry, risks should be clearly allocated between TOs and consumers. This is especially relevant given the likelihood of planning challenges across multiple schemes. For example, in the east of England, local elections have resulted in the election of an increasing number of Reform councillors with a sceptical position on Net Zero. Furthermore, the ASTI ODI Penalty Exemption Period request for Eastern Green-link 1 (EGL1) demonstrates that the burden of proof to demonstrate qualification as a delay event is very high and that qualification under the list of ASTI Delay Events is open to interpretation.

Firstly, we do not endorse the view that delay events should postpone the penalty date without adjusting the reward date accordingly. This would diminish the motivation to deliver value to the consumer by completing ahead of the revised date and creates an undesirable asymmetry for TOs. It risks making the framework unfair by removing performance opportunity if there are major events outside TOs control (e.g. major change in government planning policy), and therefore potentially uninvestable. This is a greater issue than in ASTI (which has a similar arrangement) given the immediate loss of an 'on time' lump sum where a TO fails to deliver on time. To avoid introducing asymmetry, in delay events the corresponding incentive should move back with the Delay Period.

Secondly, learning lessons from the ASTI ODI Penalty Exemption Period request for Eastern Green-link 1 (EGL1), the Final Determinations must clearly set out how the process would operate in practice. Specifically, greater clarity is needed on:

- **what will constitute a trigger for a delay event and how the days of delay should be measured** (e.g. is the delay measured from the delivery date pre-Delay Event, from the TDD, or from another "expected delivery date"). We face ambiguity without this clarity which will prevent us from assessing the potential risks of the price control. It should also ensure that incentives to beat delivery dates are retained when delay events happen by still providing a reward for delivering early given there will still be consumer value in doing so.
- **the circumstance in which an event will be judged as an "error or failure on the licensee's part"**. Ofgem's guidance on this needs to be clarified as it refers to covering delays that are not due to error or failure but also describes TOs using "reasonable endeavours" to avoid delays. Clarity is needed or there is a risk of the price control carrying too much risk and protracted assessments between Ofgem and TOs as seen on ASTI delay event engagements to date.
- **How Ofgem intends to assess and remedy the impact of a delay event for an individual project** on the incentivisation profile at a portfolio level. In our view, to operate fairly, each delay event should be considered based on the specifics of each relevant event and should not consider a wider portfolio position.
- **The inclusion of Supply Chain constraints within the list of Delay Events**. The DDs point to the list of potential Delay Events provided in ASTI Guidance as examples. However, unlike ASTI, Ofgem proposes not to allow Delay Events related to the supply chain, as it expects TOs will make use of the Advance Procurement Mechanism (APM) to address supply chain constraints. We do not agree that the existence of the APM justifies the deletion of Delay

Events related to the supply chain, as the absence of a suitable supply could still materialise and the APM only provides coverage for a limited number of equipment and services TOs need to deliver. The APM is a mechanism designed to reduce the risk of supply chain constraints but that does not mean it will eliminate it. Delay Events meanwhile are an ex-post mechanism, TOs' use of the APM should therefore be just one of the criteria Ofgem looks at to determine whether there was a supply chain Delay Event beyond a TO's reasonable control.

- We propose that the Independent Technical Adviser (ITA) is used to validate Delay Event risks and provide views on the economic case and importance of retaining incentives.

Please see supporting document NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives

Before Final Determinations, Ofgem must, in the design of this incentive:

- **Ensure reward dates move back accordingly with any agreed delay and change to penalty dates.**
- **Provide greater clarity on trigger events and circumstances judged as an “error or failure on the licensee’s part”.**
- **Clarify the process and approach Ofgem will use to measure delay days for Delay Events**
- **Include supply chain constraints as reasonable trigger for delay events because the Advanced Procurement Mechanism cannot remove all risk of supply chain delay.**
- **Ensure the ITA scope includes provision to validate Delay Event risks and provide views on incentives**
- **Please clarify the process for assessing and addressing the implications of Delay Events and confirm that this procedure will be conducted on an individual investment basis rather than portfolio wide.**

ETQ5. Do you agree with our proposed shape and size of the CSNP-F ODI-F incentive?

We agree with an incentive focused on the delivery of major network projects.

We have provided our view on the CSNP-F proposals in the Draft Determination (DD). However, there is limited information to decide whether to agree with the proposed shape and size of the incentive to be able to form a final view on the suitability and investability of the CSNP-F ODI-F proposal. **This is because it is not possible to make a judgement as to the reasonableness and workability of the incentive given the concerns set out regarding other key related parameters responses to ETQ1 – 4 above.**

We appreciate Ofgem is continuing to develop the incentive and through working groups is involving stakeholders in the process, and we will continue to support the development process.

A timely delivery incentive should maximise consumer value by rewarding what matters most to consumers, balancing acceleration benefits with capital efficiency for each project. When applied, it should be flexible enough to be tailored and balanced to the sources of consumer value for each project type. Areas of the incentive we currently support based on available information include:

- **Inclusion of material upside and relative downside for TOs.** Given the implication on consumer benefit, we support this incentive offering both material upside and relative penalties to TOs on their success in executing delivery of plans based on reasonable delivery assumptions and matters within their reasonable control.
- **We support linking the incentive to constraint costs** – where cost information is available, this approach will better align incentives with consumer outcomes and enable both consumers and TOs to share in constraint cost savings.
- **The asymmetric design of the incentive** – which recognises the inherent asymmetry and tail risk typically found in major project schedules.

Whilst we will not duplicate all previously mentioned concerns in the other CSNP-F consultation questions, key ones include:

- Links to other parameters of the incentive (see also ETQ1 and 2)
- is a lack of clarity on how caps and collars will be operated for the CSNP-F ODI-F, and;
- the process for setting dates related to Licence Obligations (LOs), where they would be imposed alongside the ODI-F date and will not align consistently with the approach adopted for ASTI projects, which sets dates 12 months after the penalty ODI date for reward. This discrepancy could have a material adverse impact on TOs and Ofgem has not set out a clear rationale for changing from the ASTI position

Concerns with other parameters of the incentive (ETQ1 & 2)

Concerns outlined in our responses to ETQ1 and ETQ2 mean we do not believe the CSNP-F incentive proposals are not investable or in consumers' interest. Setting dates early, based on immature information, creates a high chance of designing a framework which is significantly skewed against either consumers or TOs – understanding who is dependent on knowledge of the projects to which it would apply, and their respective requested and feasible dates for delivery.

We are still unclear whether 'earliest in service dates' – which ignore delivery risk – would be used. Moreover in our view, NESO is not the appropriate body to assess deliverability and, unlike Ofgem, does not have to consider criteria such as investability (which is relevant to potential negative skew of the delivery ODI-F regime based on dates chosen).

Further clarity required on the operation of caps and collars

Further clarity is needed from Ofgem on how caps and collars intend to operate for the CSNP-F ODI-F in the price control period. Our response to ETQ71 contains further detail on concerns related to the operation of caps and collars in respect of the TIM. Although Ofgem confirmed the following information points listed in the table below in response to our DDQ, Ofgem must provide further clarification on how these will be applied and work in practice.

Proposed Cap & Collar features	Value	Notes
Proposed Max Reward per project	10%	
Proposed Max Penalty per project	5%	
Annual Cap on Rewards	5%	Includes 2.5% lump sum in last year of delivery
Annual Cap on Penalties	2.5%	
Annual Minimum Reward (Floor)	2%	Pro-rated for time incurred, excludes 2.5% lump sum in last year
Annual Minimum Penalty (Floor)	1%	Pro-rated for time incurred, excludes 2.5% lump sum in last year

Licence Obligations

Furthermore, the Draft Determinations indicate that LOs will apply in addition to the ODI-F. Our view is that the ODI-F is an adequate incentive for timely delivery and that the addition of LOs is disproportionate.

The Draft Determinations state (at paragraph 4.118) that that LO dates would apply from the ODD (which is to be aligned to the TDD), a year before ODI-F penalty would apply. Ofgem has since clarified (in the DDQ response on 'Licence obligations related to the CSNP-F Output delivery' received on 22nd July 2025) that this is not the intention and has confirmed the LO date "would be set no earlier than the date at which penalties kick in under the incentive". However, this still leaves open the possibility of the LO applying from the same date as the ODI-F penalty, rather than a year later as in the current ASTI framework.

This position is unacceptable and needs to be corrected by Ofgem such that the LO (minimum requirement) date is de-linked from and set later than the incentivised delivery date. This would create significant additional open-ended regulatory risk and asymmetry, especially as under CSNP-F the intention is that dates will be determined by a NESO process outside of the control of TOs.

If they are to apply, LO delivery dates should 1) apply from a point no earlier than that at which the ODI-F penalty cap has been reached, to avoid 'double jeopardy', and 2) be set at the Project Assessment stage, when detailed design has taken place to allow greater TO confidence in the target date.

Please see supporting document NGET_RIO3_ET1-6_ET7_ET16_ET20-21_Incentives

Before Final Determinations, Ofgem must:

- Respond to and clarify all areas detailed within our responses to ETQ1 – ETQ4,
- Clarify how caps and collars will operate practically for the incentive,
- Through collaboration with TOs, agree an appropriate methodology to set delivery dates which recognises Ofgem's intention to set dates early but does not significantly skew against either consumers or TOs.
- Clarify Ofgem's position on whether 'earliest in service dates' – which ignore delivery risk – would be used, rather than properly risk-adjusted Estimated Delivery Dates.
- Ensure that the process for setting dates is appropriate in considering the deliverability of a project and is feasible to achieve to prevent negative skew of the delivery of the ODI-F regime – something NESO is not responsible for addressing.
- Remove the application of Licence Obligations alongside the ODI-F,
- However, if Licence Obligations are to be imposed:
 - The minimum requirement date is de-linked from and set later than the incentivised delivery date.
 - Apply from a point no earlier than that at which the ODI-F penalty cap has been reached, to avoid 'double jeopardy', and,
 - Be set at the Project Assessment stage, when detailed design has taken place to allow greater TO confidence in the target date.

ETQ6. Which of the two proposals for the Connections Capacity ODI-F target setting methodology do you think is most appropriate and why?

We agree with having an incentive linked to facilitating timely connection of customers to our network. However, neither of the two proposals provide enough detail for us to fully assess their appropriateness in driving consumer value and ensuring the appropriate level of risk to maintain investability. Instead, we provide our proposed solution to filling these gaps in response to ETQ7.

An example of the gaps include there being limited explanation of design details such as how the target would be set, how performance would be measured, the value of the incentive (other than a proposed cap and collar) and even the type of connections to be incentivised.

In the Draft Determination, there is limited to no explanation of design details such as how the target would be set, how performance would be measured, the value of the incentive (other than a proposed cap and collar) and even the type of connections to be incentivised. In a working group held on 19 August 2025 Ofgem provided some further information on its proposed design. Our comments on each of the Ofgem's proposed options are based on the information in the Draft Determination and this working group.

On option 1, rewards for on-time or expedited **connection of projects needed to meet Clean Power 2030** (and penalties for being late):

- **Objective:** An incentive based on project-by-project delivery dates risks promoting an inefficient approach to network development.
- **Scope:** Ofgem has clarified since the Draft Determination that this incentive would include demand and embedded generation projects. We support this as these connection customers are equally important in facilitating Government's objectives of economic growth and Clean Power 2030.
- **Performance target:** We support Ofgem's position, shared at the working group, that the maximum reward should be available for on time or early delivery. We recognise that this incentivises on time rather than early delivery of connections but, given connecting customers may not be able to be ready faster this may be acceptable to them.
- **Risk/reward balance:** We support the need for a deadband in this design, where no reward or penalty is incurred, but do not support Ofgem's position that 30 days is an adequate length to manage risks. The incentive target (project delivery date) is set before, for example, any detailed engineering has been completed, the supply chain has been engaged and outages have been booked / agreed. Our view is that the level of uncertainty on delivery is therefore far greater under the proposed target setting methodology on this incentive than the CSNP-F delivery incentive where a deadband of 12-months is proposed. The asymmetry of the proposed caps and collars (+0.4% to -0.2% RoRE) does not compensate for the material risk on We will provide further feedback to Ofgem on this point through continued engagement.
- **Exclusions and exemptions:** The issue noted above is further compounded by Ofgem's position that there would be no exclusions or exemptions other than delivery dates moving where the customer has requested it. We are currently (subject to completion of the re-ordering of the connections queue) expecting in the region of 120 to 140 generation and demand connection projects over RIIO-ET3 alongside work to support the connection of embedded generation. A process to allow for changes in required connection dates would be very burdensome for TOs and Ofgem to manage but we consider it essential alongside a longer deadband in order to ensure risks and manageable and the investability of the framework is maintained.

On option 2, rewards for adding capacity (MWs) **in line with or exceeding expected capacity increases** due to funded projects (and penalties for lower capacity additions), we agree with Ofgem's concern with establishing an annual process for updating the target. We are also unclear how an annual change in the target would provide the appropriate level of incentivisation. It could be the case that Ofgem's funding decisions occur when projects are already in train, reducing the opportunity for actions that would expedite projects. Additionally, we consider there could be duplication between this incentive and the CSNP-F delivery incentive as Ofgem proposes that the CSNP-F delivery incentive could be applied to load projects beyond those established by the CSNP.

The two options proposed by Ofgem are likely to drive different outcomes and therefore Ofgem's objective for this incentive is still unclear. We consider that **the right objective is for a connections incentive to positively encourage creation of capacity to facilitate timely connections for customers and provide for faster connection times over the long term**, supporting individual customers and wider consumers (and facilitating Government policy) by allowing connection of low carbon generation and strategic demand quicker than would otherwise be the case.

Ofgem must engage with TOs and other stakeholders to finalise the incentives in advance of the Final Determination. In our response to question ETQ7, we provide full detail of the design of an incentive that meets our proposed objective. We recommend using our proposal as the basis for the design of the incentive.

ETQ7. Do you have any further considerations on our chosen direction for a RIIOET3 Connections Capacity ODI-F, including detail on how the targets could be built up?

We do have further considerations on the chosen direction for a connections capacity ODI-F. We have developed the detail of an incentive aligned with the objective for a connections incentive outlined in our response to question ETQ6.

The table below provides this design detail.

Design parameter	Description
Scope	<ul style="list-style-type: none"> Transmission-connected generation, transmission-connected demand and embedded generation.
Performance measure	<ul style="list-style-type: none"> A measure (MWs) of customer capacity created and ready for connection each year. TO performance based on delivery of Stage 1 commissioning of the assets, the final stage before the customer physically connects. Both asset build and commercial solutions count towards performance.
Target	<ul style="list-style-type: none"> Target to be developed from information in connection offers. Annual targets (for each of the five years of the T3 price control period) set at outset of price control and on a portfolio level based on MWs and dates in connection offers – data on Available for Commercial Load (ACL) dates available in Transmission Owner Construction Offers (TOCOs). If the timetable for connection reform slips then all necessary information may not be available for the Final Determinations and a clearly outlined and transparent methodology may be needed in place of the MW target for later years.
Incentive value	<ul style="list-style-type: none"> £ per MW calculated for each TO based on target volumes and overall scale of opportunity/risk Ofgem has proposed.
Cap and collar	<ul style="list-style-type: none"> Support Ofgem's position for an envelope of performance opportunity based on RoRE of 0.4% to -0.2%. Assessment of whether the cap/collar has been breached is likely to require a post RIIO-ET3 assessment. Volumes vary by year, and incentive value (in £ per MW) set based on seeking overall performance envelope. So a cap and collar set to meet an average year will be breached in years with higher volumes but outperformance in such years should be allowed if overall the cap is not breached (and likewise on the downside).
Risk/reward balance	<ul style="list-style-type: none"> A sliding-scale approach to value available, to recognise that meeting the target will be a stretch. Must be recognised that achieving Clean Power 2030 and delivering increased demand connections will be very stretching. c. 30 bps reward for meeting target would provide this recognition. Provides scope to earn additional reward for facilitating earlier delivery of known customer projects and to invest in creating capacity ahead of known need, but recognises that with a firmer connections queue there is a good degree of certainty on what will be needed.
Exclusions and exemptions	<ul style="list-style-type: none"> Ability to seek a change in the target based on agreed procedures related to inability to create capacity because system access request has been refused, planning and consenting decisions or land purchases have not been possible under reasonable/agreed timelines, there have been force majeure supply chain restrictions, or in extremis changes in government policy impacting volumes.

This proposal is based on, but creates a broader scope than, Ofgem's project-by-project approach. Creating a portfolio from information in customer level connection offers means the target could be achieved in different ways which places the onus on the TO to manage risks within its control and supports the objective of supporting efficient delivery of network development.

Ofgem should engage with TOs and other stakeholder to finalise the detail of the incentive. This must be completed ahead of the Final Determinations to provide confidence to TOs and stakeholders that there will be an effective incentive that appropriately balances risk and opportunity for additional returns for TOs.

Please see supporting document NGET_RIIO3_ET1-6_ET7_ET16_ET20-21_Incentives

ETQ8. Do you agree with our proposed design of the Community Benefit Funding pass-through mechanism?

We agree with the principle and intent behind Ofgem's proposed design of the Community Benefit Funding pass-through mechanism and welcome Ofgem's confirmation that it will allow the recovery of costs for community benefits, in line with Government's recently published guidance. However, we do not support the design of the mechanism in full due to several outstanding issues set out below. These require resolution to ensure the mechanism is consistently applied, practical to implement, and better aligned with Government policy.

We welcome Ofgem's Draft Determination that, as the Government's guidance determines the levels of investment to be made to community benefits, Ofgem will not assess the main community benefit fund and will only conduct an ex-post review of administrative costs at a portfolio level where further assurance is required. However, in order to fully support the pass-through mechanism for Community Benefit Funding, as proposed by Ofgem, the following issues should be addressed:

- We seek confirmation that the licence condition implementing this proposal will apply to all projects in scope of Government guidance, including those under the ASTI framework. We note that the Community Benefit Funding pass-through licence condition has now been published as part of the initial licence consultation published on 30 July, and we will provide feedback to Ofgem through this channel. We propose that the same regulatory mechanism applies across the whole portfolio, to ensure consistent treatment. However, for projects under the ASTI framework, we will continue to reflect community benefit costs in each project's Project Assessment submissions for visibility and to ensure clear and transparent governance (noting that they will be input into the RRP process for forecasting and true-up).
In addition, updates to the ASTI Submission Guidance needs to be considered where licence changes via RII0-T3 change existing ASTI licence conditions.
- The reference to administration costs in Draft Determinations should accurately reflect the position in the Government guidance. The ET annex of the Draft Determination currently states that "*administration costs should normally be significantly under the 10% limit set by government*", whilst paragraph 3.71 in the ET annex states "government has provided that TOs may spend no more than 10% of the community funds total on administrative costs."

However, the Government guidance states that "*this guidance does not prescribe how much delivery costs will be as we appreciate this will differ on a project-by-project basis. However, we expect delivery costs to be under 10% of a community fund package. In exceptional circumstances, there may be instances when a community may require more support from a developer in developing their community fund package and, in such instances, delivery costs may be higher.*"

We do not consider Ofgem's reference to administration costs being 'significantly' under 10%, or its interpretation of the 10% figure as being a strict upper limit, to be consistent with Government guidance, or be practical. This is particularly relevant given the list of activities set out in the guidance which could be considered under administration costs. If a strict cap of 10% is applied, Ofgem should consider and address how this would limit the support provided to communities.

In its response to NGET DDQ 071, Ofgem has confirmed that annual forecasting will be available for the pass-through costs, and NGET will input these into the RRP process for forecasting and true-up. This is important for NGET's financial planning and governance, given that we expect community benefit costs, in line with Government guidance, to reach in excess of [REDACTED].

On the understanding that forecasting will be available, the above issues are the main areas requiring a resolution. Ofgem should fully consider and resolve these outstanding issues as part of Final Determinations.

Community Benefit for projects not in scope of government guidance

Separate to the above, we note that in its response to NGET DDQ 041 Ofgem has rejected our request for a separate allowance to continue to deliver a community benefit provision for projects not in scope of Government guidance. We disagree with this outcome. Our T3 business plan includes a significant amount of maintenance and operational activity, such as overhead line refurbishments and tunnelling projects, which will not receive project-specific allowances in line with government guidance. We know from existing projects such as London Power Tunnels that stakeholders, including MPs, Local Authorities, and local communities, have welcomed our approach to delivering a community grant provision to support communities in areas affected by these types of projects, and this has been

important to build public acceptability of this vital work. We would like to continue engaging with Ofgem on the value delivered by this programme and its future in T3.

ETQ9. What are your views on our consultation positions for the TOs' EAP commitments in RIIO-ET3?

We broadly agree with the consultation positions on the TOs' EAP commitments in RIIO-ET3, but we have concerns regarding the level of funding allocated to several key areas.

While we are pleased to see support for the majority of our EAP commitments, we note that some of our commitments have not been fully funded. The lack of funding in not only limits our ambition for those specific commitments but also affects our ability to deliver across the wider EAP, given the interdependencies between themes. Reduced funding in one area can have a knock-on effect on delivery in others. To ensure delivery across all of our EAP commitments we request that Ofgem approves funding for our low carbon construction, energy efficiency and oil containment commitments, and our FG1 circuit breaker replacement programme. Further information on the impact of not fully funding these commitments is provided in consultation questions ETQ42, ETQ43.

Further information on each of our relevant commitments is provided below.

B4.4 Low Carbon Construction

We note that Ofgem proposes to reject our request for a portfolio-level UIOLI pot for low carbon construction. Ofgem has recommended that we move pot 1 into baseline funding, and explore alternative funding options for pot 2. If these funding requests are not fully approved, it will impact on our commitment to deliver scope 3 emissions reductions – specifically our target to *contribute to the National Grid Group Scope 3 emissions reduction target of 37.5% from 2018/19 baseline by 2033*.

Without appropriate funding, or if funding is only available through innovation mechanisms that require competitive bidding against other projects, we may need to reassess the feasibility of our Scope 3 commitment. Further detail on this is provided in ETQ42 and ETQ43.

B4.6 Circular Economy

The low carbon construction funding overlaps with our circular economy commitment B4.7 - *improve our circular economy maturity levels, reduce waste and recycle/re-use more content in construction*.

We have set a target within this commitment to use 10% recycled / reused content in major construction projects by 2031 and for zero avoidable waste in construction by 2030. Several of the low carbon materials within pot 1 and the emerging opportunities pot 2 will support these targets. For example, use of low carbon steel and aluminium, which has a greater recycled content than higher carbon alternatives, and the use of 3D printing which reduces waste during project construction. Rejecting our low carbon commitment will mean we are unable to fund these proposals.

B4.3 Sustainable Operations

We note that Ofgem proposes to reject the funding request for our substation energy efficiency programme. The energy efficiency programme supports commitment *B4.1 Reduce our own carbon emissions: Deliver scope 1, 2 and 3 emissions reductions in line with a 1.5-degree Science Based Target (SBT)* by contributing towards our scope 1 and 2 emissions reduction targets through reducing our use of electricity and gas. Substation electricity use, excluding line losses, is our most significant Scope 2 emissions source. In FY25, it accounted for over 87% of our Scope 2 emissions (excluding losses). To assist Ofgem in considering this funding request, we have provided further information, as requested by Ofgem, in NGET_RIIO3_NGETQ10_DD9b_Submetering.

We also note that whilst approving our proposals to repair SF6 leakage on our network, Ofgem has proposed to reduce funding for some of our FG1 circuit breaker replacement programme for 45 assets which hold a combined inventory of 854kg of SF6 that was proposed as part of our non load submission (EJP ref AH-T3 EJP portfolio). This reduction in SF6 inventory reduces the risk of future leaks and supports delivery of our scope 1/SF6 commitments, as well supporting the need to move to proactive intervention to deliver on our longer term SF6 targets by reducing our total inventory. The proposed funding reduction would leave 280kg of SF6 filled assets at high risk of leakage, undermining our ability to deliver environmental improvements and manage asset risk effectively

Environmental Management Systems

We note that Ofgem requested further detail and spend profiles for oil containment measures proposed in our T3 business plan.

Commitment B4.11 highlights the need to build on our environmental management system and reduce leaks from oil filled assets. Our response identifies the key environmental criteria relating to asset management health that we use to inform investment and our continual improvement. As part of our ISO14001 environmental management system oil

filled assets are identified as a key risk within our portfolio. As part of our commitment to continual improvement (which is required to maintain our accreditation) we assess, manage and improve the environmental controls on our assets. Without this investment our ability to maintain accreditation would be put at risk. We receive regular information requests from investors, key stakeholders and the general public on environmental incidents, which include oil leaks. The loss of accreditation would lead to significant reputation, commercial and operational risk.

Investor Expectations

We acknowledge the need to balance consumer bills / value for money with investability, and the need to ensure a financial return that will attract the level of investment needed to deliver the energy transition. We also hold the view that how we deliver our infrastructure can impact our ability to attract investors.

Investor interest in sustainability has grown over the last decade, driven by increasing emphasis on global initiatives like the climate and biodiversity COP's and the Global Biodiversity Framework, as well as increasing disclosure expectations relating to climate and nature. Currently, most investor queries focus on sustainability relate to our climate impacts. In terms of questions pertaining to our transmission business, these tend to be related to SF6 emissions and how we are reducing them and our line losses strategy. We are concerned that reductions in our T3 funding settlement that could impact our climate targets and reduce the appeal of investing in National Grid compared to our peers. This particularly relevant given that 100% of our capital expenditure in NGET is classed as green under the EU taxonomy, enabling us to issue green bonds and access a broader pool of sustainability focused investors.

We are also seeing an increase in nature related questions from our investors. For example, one of our top 20 shareholders recently set out expectations relating to disclosures, nature targets and nature positive outcomes. The Taskforce on Nature Related Financial Disclosures (TNFD) has prompted queries on our plans to disclose our nature impacts, and UK Government is currently considering how TNFD should be integrated into its plans for Sustainability Reporting standards.

Ofgem should revisit its funding positions and, by Final Determinations, approve full funding for our commitments in low carbon construction, energy efficiency, oil containment, and FG1 circuit breaker replacement. This is essential to ensure delivery of our full suite of EAP commitments, meet stakeholder and investor expectations, maintain momentum across interconnected EAP themes.

ETQ10. Do you have any views on whether the Innovative Delivery Incentive and/or SO:TO ODI-F should be used to incentivise TO action regarding transmission losses?

Our view is that without further engagement and clarification on intent, neither the Innovative Delivery Incentive nor SO:TO incentive, as currently proposed, would be the most effective mechanisms for encouraging TO actions to reduce transmission losses.

We are committed to reducing transmission losses. Our approach is guided by ensuring that decisions are economically justified and consider transmission losses in linear assets, where they are material to the investment case.

Our experience in RIIO-T2 (and as currently proposed for RIIO-T3) of the SO:TO incentive is that it measures consumer benefit via constraint avoidance forecast and measured. Whilst we would be open to discuss Ofgem's views on how to feasibly include losses, our view is that the SO:TO incentive is not suited to incentivising TO action in this area due to the immaterial effects that such short-term constraint avoidance activities have on transmission losses.

We have delivered and continue to pursue innovative solutions that contribute to loss reduction. These include uprating of 275kV assets to 400kV, identifying the feasibility of implementing ultra-high voltage direct current (UHVDC) systems, and the use of efficient materials and technologies. While losses are not the primary driver for these innovation projects, they are a key consideration in our innovation pipeline and strategic planning.

We consider that the Innovative Delivery Incentive could provide opportunity to embed our loss reduction strategy in the wider context of our innovation strategy. However, this must be considered against: the complexity in calculating financial benefits, the lead time required for some innovations to show results, and the small/incremental nature of loss savings not triggering the materiality threshold proposed for the Innovative Delivery Incentive.

Notwithstanding, relevant behaviours are outlined within the incentive's scope - innovations in design/engineering, collaboration with NESO, and rollout of NIC/NIA/SIF innovations are directly applicable to identifying and implementing cost effective, scalable measures that could support minimising transmission losses. Whilst we recognise the potential of the Innovative Delivery Incentive to support a reduction in losses, we suggest Ofgem consider some of the potential challenges outlined above.

Ofgem should engage with TOs to discuss perspectives on practical application of incentivising TO actions on transmission losses reduction before implementing any such incentives in the Final Determination.

ETQ11. Do you have any views on our proposed approach to biodiversity funding, notably whether it is appropriate or not for consumers to fund biodiversity outputs beyond legislative requirements?

We do not agree with Ofgem's proposed approach to biodiversity funding as there is strong stakeholder support, as well as government policy, to fund nature and biodiversity outcomes beyond what is legally required, and the incremental impact on bills is minimal (maximum of 6 pence per annum by 2030).

As part of RIIO-T3 and energy transition delivery costs, and in our role, we agree with stakeholders that it is appropriate for consumers to fund nature and biodiversity outcomes beyond legal requirements.

- The investment in biodiversity enhancement associated with non-statutory construction activities, represents excellent consumer value, with our estimate that the addition to the average consumer bill by 2030 will be between 1 and 6 pence per year, based on an updated costs estimate of between £45m (low) and £134m (High) over the T3 period.
- NGET is subject to the biodiversity duty set out in section 40 of the Natural Environment and Rural Communities Act. This places a duty on us to consider how we can conserve and enhance biodiversity through the exercise of our functions. The proposals we have developed for both statutory BNG/NBB and biodiversity outputs beyond legislative requirements represent our response to that duty and will ensure appropriate levels of protection and enhancement are provided for all projects whilst aligning to core principles defined within legislation.
- We are seeing a growing stakeholder and community expectation to go beyond the statutory minimum and there is growing evidence that this supports more positive planning and consenting outcomes
- There is an abundance of government policy pertaining to improvement of nature beyond the statutory minimum, including in DESNZ's own Clean Power 2030 Plan, as well as precedent set by OFWAT for the water sector
- TOs investment into biodiversity enhancement beyond minimum legal compliance can act as an enabler for much needed nature recovery across the whole of the UK and support delivery of associated benefits for nature and communities across the whole of the UK

Following OFGEM's responses to DDQ NGET078 we are keen to continue collaborating with Ofgem and other TO's to agree the scope of BNG funding, including transitional projects spanning T2 and T3. We acknowledge that the various consenting regimes and BNG requirements are complex, and we wish to ensure that legal obligations and policy requirements are met to support project delivery, and continue to deliver value for nature and consumers.

For final determinations, Ofgem should revisit the proposed approach and include provision for funding in line with our ambition to deliver at least 10% BNG or NBB with additional environmental and societal benefits beyond the legal minimum and for all NGET construction activities. This would also align with government policy pertaining to improvement of nature beyond the statutory minimum including in DESNZ's own Clean Power 2030 Plan, as well as precedent set by OFWAT for the water sector.

We have provided additional evidence supporting our response in the following sections:

- Revised costs of delivering BNG / NBB commitments in T3
- Continual Improvement
- Stakeholder Confidence in NGET's BNG Approach
- Legislation & Policy, underpinning NGET's approach
- The Case for Non-Statutory BNG - Consumer Value
- Precedent for taking action beyond legislative compliance

Revised costs of delivering BNG / NBB commitments in T3

Following submission of NGET's RIIO-T3 Business Plan, and the initial BNG cost range estimate provided in response to NGETSQ109 and subsequent non-statutory % estimate detailed within NGETSQ145, we have revised our costs which represents a lower cost range.

The revised calculations estimate the proportion of BNG unit requirements and costs for construction projects with non-consenting BNG/NBB requirements to be between **10-15%** of overall T3 requirements (*assuming that BNG for Nationally Significant Infrastructure Projects (NSIPs) becomes mandatory in 2026 as planned*).

In T3 we expect to see the delivery costs for statutory BNG increase and non-statutory BNG costs reduce. This is because of the almost five-fold increase in investment for T3, and more consenting regimes being brought into scope for BNG.

The summary table below reflects a revised BNG cost range estimate for T3 of between £360 - £1,075m, with Non-stat costs estimated to be between £45m and £134m. Cost to consumers ranges from 1 pence-6 pence for non-statutory, and 13-41 pence for statutory BNG/NBB depending on the cost unit range.

	T2			T3	
BNG Unit Cost Range*	Low	Ave	High**	Low	High
% of Total BNG/NBB requirements for Non-stat	85%			10-15%	
Est Total Non-stat BNG/NBB cost (£m)	£94	£117	£140	£45	£134
Est Non Stat cost to Consumer				1-3p	5-6p
Est Total Statutory BNG/NBB cost (£m)	£17	£21	£25	£315	£941
Est Statutory BNG/NBB cost to consumer ²				13-14p	38-41p
Total BNG/NBB costs Est (£m)	£111	£138	£165	£360	£1,075

Please note: This revised estimate includes a broad range of uncertainties and assumptions due to the varying stages of development and maturity projects. These are explained in Appendix 1

Continual Improvement

We need to accommodate a range of stakeholder expectations in delivering our T3 proposals. This includes local communities, eNGOs and investors. By limiting BNG / NBB delivery to the statutory minimum we are taking a significant step back in ambition at a time when the voice from all these groups is very firmly endorsing the need to do more for nature.

National Grid has had a Net Gain commitment in place for the duration of T2 (2021-2026). This commitment, set ahead of legislative requirements introduced via [Schedule 7A of the Town and Country Planning Act 1990 \(as inserted by Schedule 14 of the Environment Act 2021\)](#) represented NGET as a leader in the space, demonstrating positive action and building relationships with a range of strategic delivery partners and industry peers.

Looking forward to T3, our plan builds on these foundations and represents an evolution from T2 by focussing on delivery of BNG / NBB with wider environmental and societal benefits. This is aligned with policy expectations detailed within NPS EN1 to seek to incorporate improvements in natural capital, ecosystem services and the benefits they deliver as part of BNG delivery. At the time we developed our proposals this represented a practical balance between stakeholder expectations of significantly greater ambition (e.g. requests for 20% BNG), with our desire to provide a proposition that provides consumer value.

Recognising the need for consumer value and delivery challenge due to a step change in our investment scale, NGET has set up a Climate and Nature procurement framework. This framework of suppliers will provide high integrity BNG / NBB deliverables alongside wider environmental and societal benefits at average costs aligned with UK Nature Market price signals. This framework provides an option to deliver defined outcomes for nature through a competitive process and we are confident this will ensure we maintain excellent consumer value for BNG units or environmental outcomes purchased via this framework.

Stakeholder Confidence in NGET's BNG Approach

Our T3 Environmental Action Plan was developed using a range of internal and external stakeholder input which is summarised in our [EAP on pages 86-91](#). We also held a webinar in July 2025 with over 35 stakeholders to gather their views on Ofgem's Draft Determinations. Responses from our recent stakeholder consultation included:

1. **Strong calls for higher BNG / NBB % commitments** across all development types to align with national policies and international commitments.
2. **Stakeholders (e.g., The Wildlife Trusts) suggested the position in Draft Determinations is contrary to government policy** and international commitments on biodiversity and is a regressive step to the guidance we have been following in RIIO-T2.
3. **Emphasis that BNG benefits are substantial and outweigh costs in the overall project.** Some stakeholders challenged Ofgem's view that BNG costs would be a significant burden to consumers and commented that removing BNG on non-statutory projects is going to make negligible difference to consumer bills.
4. **Support for extra BNG measures and greater flexibility.** Coastal Partnerships Network advocated for doing more than the statutory minimum to enable an integrated approach to BNG that address the challenging land-sea interface.
5. **We recognise the need to deliver consumer value**, however we also need to recognise the wider stakeholder landscape, particularly the expectations of influential stakeholders that NGET continue as leader in this space. These organisations are key stakeholders for our projects and their support is important in gaining appropriate support and permissions for our projects.

² Average cost to consumer for statutory BNG is 25-28 pence

Legislation & Policy, underpinning NGETs approach

In addition to BNG becoming a statutory requirement for projects under the Town and Country Planning Act 1990, there is a substantial and growing volume of government legislation, policy and ambition aimed at restoring and enhancing the natural environment.

- The Natural Environment and Rural communities Act (NERC) Section 40 places a duty on public authorities to conserve and enhance biodiversity through the exercise of its functions. As a public authority we developed T3 nature proposals that will fulfil our obligations under this duty, in ensuring we commit to delivering a net gain for all our capital projects.
- The Natural Environment White Paper (2018) and the Environmental Improvement Plan (EIP) 2023 sets out government plans and targets for improving the natural environment. In the EIP UKG has committed to delivering at least 500,000 hectares of wildlife rich habitat by 2042, with an interim target of 140,000 hectares by 2028. Guidance on the types of actions that can be counted towards this target confirms that the 10% net gain delivered through BNG will count towards this target.
- Local Nature Recovery Strategies (mandated by the Environment Act 2021) are currently being developed by 48 responsible authorities in England. The strategies set out priorities for nature recovery. UK Government is implementing a package of measures to support delivery of LNRS, including a new duty on all public authorities to have regard to relevant local nature recovery strategies.
- The Welsh Environment Bill aims to tackle the climate and nature emergencies by strengthening environmental governance and reversing biodiversity loss. It introduces a legally binding framework for biodiversity targets through amendments to the Environment (Wales) Act 2016, which requires public authorities to comply with the biodiversity and resilience of ecosystems duty.
- The Clean Power 2030 Action Plan pages 41-42 highlights the interconnectedness between climate and nature, a theme we have echoed in our T3 Environmental Action Plan. It highlights the government's commitment to restoring nature as well as calling out the need to improve nature, as opposed to protecting the little we have left.

By committing to delivery of Biodiversity enhancement with wider environmental and societal benefits, NGET as a TO (and Ofgem as a regulator) can play a pivotal role in supporting the UK Government's ambition to deliver the energy transition in a way that also accelerates progress towards national biodiversity and nature targets. Such a commitment would not only demonstrate alignment with government policy but also sets a clear precedent for the level of environmental responsibility expected across the sector by our stakeholders. Regulatory support for this ambition is essential to ensure that infrastructure delivery and environmental restoration go hand in hand.

The Case for Non-Statutory BNG - Consumer Value

Based on an estimate of BNG / NBB requirements for construction activities delivered without a formal planning or consenting requirement, we estimate the non-statutory BNG costs to be ~£45m throughout the T3 period, representing around an additional 1-3 pence (low) or 5-6 pence (high) per year on the average consumer energy bill.

This is in comparison to an average estimated increase of between 25-28 pence per year for actions required to deliver statutory BNG/NBB.

It should also be noted that to mitigate the effects of our activities on nature and ensure preservation of amenity, as required under Schedule 9 Electricity Act 1989 and to maintain a position of 'no net loss' (as opposed to a net gain) there will still be an associated cost - the alternative cost to spending £45m on non-statutory BNG will not be £0.

We acknowledge Ofgem's concern regarding proportionality and consumer value of nature-based commitments beyond legislative requirements. However, we have ample evidence that consumers from all demographic groups put nature as a high priority, and our view is that the above costs represent excellent value for money. Some of this evidence is summarised below.

The importance of Nature to consumers:

- In a study undertaken by Yonder Consultancy in November 2023 consumers indicated that protecting and improving wildlife and nature habitats is one of their top 5 priorities for National Grid in delivering our future network plans.
- Further research carried out in February 2025² highlighted that the impact of construction activities on natural habitats and wildlife was listed as one of the primary concerns for consumers.

Willingness to Pay:

- Evidence from stated preference studies underlines that the public is not only concerned about nature in principle, but willing to support and value its restoration.
- [Defra study \(2022\)](#) – A survey of 5000 people and 15 in-depth focus groups found people were willing to pay

for improved biodiversity and species abundance on the scale of several hundred pounds per household per year

Supporting evidence:

["Nature-Based Solutions and Public Support for Biodiversity and Carbon in the RIIO-3 Context"](#), a paper commissioned from Sustainability First sets out in detail the comprehensive evidence for customer and citizen support for biodiversity/nature - beyond statutory compliance. In addition, they make the case for more direct customer benefits, particularly in rural areas. Key highlights of the report include:

- **The wellbeing and social benefit of nature is well evidenced, particularly at community level** – and has grown significantly with the greater appreciation of nature and green spaces following COVID lockdowns. Co-benefits such as Carbon capture and flood alleviation are now widely accepted: indeed, ministers have stated that they aim for 18% of all funding for flood reduction to be in the form of nature investment.
- **The case for biodiversity corridors, set out in Sir John Lawton's report to Defra ministers** – Grid's transmission network has the potential to become a powerful exemplar here.
- **Direct economic benefits to customers from nature spend** – with a growing body of case studies for how community nature spend can help deter planning appeals and thereby speed up and reduce costs of infrastructure planning and delivery. Ministers have stated that they aim for 18% of all funding for flood reduction to be in the form of nature investment.

Precedent for taking action beyond legislative compliance

Within the UK, business leadership and investment into voluntary nature markets and nature restoration beyond compliance is essential to meet UK Government's commitments. Our T3 Biodiversity enhancement commitments will enable a broader and varied contribution to nature recovery actions.

Industry Example: OFWAT as part of the Price review 2024 (PR24) has funded a range of non-statutory and statutory biodiversity enhancement that enables outcome-focused delivery beyond legal compliance. In addition, OFWAT introduced a Biodiversity Performance Commitment (PC) to incentivise water companies to conserve and enhance biodiversity in the exercise of its functions. This PC uses the Statutory Biodiversity Metric.

ETQ12. What are your views on our consultation position for the IIG ODI-F target methodology in RIIO-ET3, in particular the bespoke treatment of SHET?

We support the proposed design of the Insulation and Interruptions Gas (IIG) emissions incentive for ourselves and SPT. We agree, based on the information Ofgem has provided, that the same design would not be appropriate for SHET.

In our business plan we committed to reducing emissions from SF₆ by 50% by the end of RIIO-ET3 (from a 2018/19 baseline). This commitment is in line with our Science Based Target. We evidenced investment requirements for the replacement and removal of assets in our business plan to support us meet this commitment. The design of the incentive encourages us to deliver our commitment, with a small reward (commensurate with the value to consumers) for delivering it quicker, and penalises us if we fall short.

Ofgem should maintain its current position at Final Determination.

ETQ13. Do you consider that we should use the IIG Exceptional Event mechanism to manage potential issues with historical IIG inventory data? If so, why?

We agree that the exceptional event mechanism should be used to address any issues that arise as a result of historical inventory data not being accurate. However, we disagree with the proposal to have a monetary threshold for claiming an IIG Exceptional Event set at the value of 5% IIG emissions as this would expose TOs to the risk of material financial penalties if an emissions target is missed as the result of a qualifying exceptional event.

We support Ofgem's position that it is not appropriate to penalise TOs for issues that arise due to the accuracy of historical recording of gases within assets. It is appropriate to offer a route to exempt such proven issues from penalty through the exceptional event mechanism with the burden of proof sitting with a TO. We will provide feedback to Ofgem's licence consultation on whether the proposed definition appropriately captures this policy intent.

We disagree with the proposal to have a monetary threshold for claiming an IIG Exceptional Event set at the value of 5% IIG emissions. This would expose NGET to the risk of material financial penalties where missing an emissions target is the result of a qualifying exceptional event. The average annual exposure of 5% of the emissions target for NGET is £2.36 million, based on the proposed IIG target in the Draft Determination and a non-traded carbon price of £290/tCO₂e.³ We do not see the need for this additional policy on exceptional events and consider the existing threshold that compares the value of the exceptional event to the cost of the submission as appropriate.

By the final determinations, Ofgem should confirm the use of an IIG Exceptional Event mechanism, noting our feedback thorough the licence consultation, but revert the monetary threshold to the existing arrangement.

³ Based off the T3 average of emissions from the Green Book Supplementary Guidance

ETQ14. What are your views on our consultation position for the SF6 Asset Intervention PCD in RIIO-ET3?

We agree with Ofgem's intent for the SF6 Asset Intervention PCD. As there is limited further detail provided, we have suggested an approach that is proportionate and consistent with that used in RIIO-T2.

For NGET, Ofgem proposed to include its efficient view of funding for all output requests in the SF6 Asset Intervention EJP under a PCD. We welcome the fact that Ofgem supports our ambition to deliver a 50% reduction in SF6 emissions by 2030 (from a 2018/19 baseline) in line with the Science-Based Target to reduce our Business Carbon Footprint. We therefore agree with this part of Ofgem's consultation position.

Ofgem propose that these works should be included in an SF6 Asset Intervention PCD. There is no further discussion regarding the nature of this PCD, but we believe that the following approach is proportionate and consistent with the approach taken in RIIO-T2:

1. **Evaluative PCDs** – These are appropriate for material, site-based interventions where the scope (and hence cost) varies significantly from site-to-site. The majority of the proposed interventions are site-based and therefore these can be covered by a number of evaluative PCDs.
2. **Mechanistic PCD** – Mechanistic PCDs are suitable when work is (i) countable, and (ii) repeatable such that interventions have consistent unit costs. In such cases, allowances are set for a capped volume of work and the recovery of allowances for any non-delivery of work is automatic. There is one area of our SF6 submission where we believe that a mechanistic PCD is appropriate. This is for the palliative coating element of the submission which aims to coat a number of gas zones across [REDACTED]. It is possible to establish a unit cost per gas zone, and hence have a mechanistic PCD to ensure that funding tracks delivery.
3. **Baseline funding** – The £4.67m requested for SF6-free IIG adaption and management is not for the delivery of projects with outputs, and therefore a PCD is not appropriate. This is to provide NGET with the required tools and equipment, such as new gas carts and gas mixing plant, to effectively manage and continue to adopt SF6-free alternatives across the transmission network. It is therefore more akin to a Network Operating Costs such as STEPM which receive baseline funding. We therefore propose that this minor proportion be provided with ex ante baseline funding and no PCD.

The spend to complete investments commenced in RIIO-T2 and now completing in RIIO-T3 should remain linked to the relevant T2 evaluative PCDs. The agreed RIIO-T2 allowance profile needs to be adjusted to reflect the revised output dates; this should occur in line with the T2 PCD process for delayed outputs.

It is not appropriate to share the detailed cost breakdown for the above in a public consultation document because the cost of the works is commercially sensitive. Instead, we will provide a separate technical note to summarise proposed evaluative PCDs and the mechanistic PCD.

For final determinations, Ofgem should continue the development of the SF6 Asset Intervention PCD using our feedback above and separate technical note. We will also continue to work with Ofgem to develop and clarify the methodologies for such PCDs.

ETQ15. What are your views on our proposals for the RIIO-ET3 ENS ODI-F, including the two different target setting methodologies we have shared?

We support a continuation of the energy not supplied (ENS) incentive, however, we do not support the methodologies used to derive the two targets being consulted on. We also consider that the exemptions and exclusions regime should be expanded to recognise that events of lost supply are not always within a TO's control or do not cause consumer detriment.

Ofgem state that the ENS incentive is to encourage improvement in network reliability in an efficient way. We argue that this is not the case. Reliability is already very high. Last year network reliability was 99.999998% and we are targeting maintaining it above 99.9999%. The incentive therefore serves to support efficient maintenance of this high standard of reliability, rather than to drive further improvements. That is why it is significantly skewed to the downside, with very limited upside opportunity. As a result, we aim to manage risk of energy not supplied events rather than pursuing actions that would result in a reward.

Given the high level of reliability, we understand why the incentive is skewed to the negative. However, this has implications for what constitutes a reasonable target. The target should encourage efficient management of the network without encouraging high cost or overly risk averse actions that could be detrimental to the system as a whole. A very low target will drive these inappropriate behaviours.

We agree with Ofgem's position that managing ENS is becoming more challenging. Despite this position, the Draft Determination proposes two targets: one of which is 85% lower and the other 15% lower than our current RIIO-ET2 target. Ofgem's position and the targets it has proposed are not aligned.

Ofgem's favoured methodology derives a target of 125 MWh per annum for NGET (15% lower than the current RIIO-ET2 target). The target setting methodology takes a TO's current target and subtracts the average of the average performance in RIIO-ET1 and the average performance in the first three years of RIIO-ET2. The target derived from this methodology is described as reflecting "the reliability improvements achieved during RIIO-ET2", but this is not the case. If this was the case you would expect the target to be lower the better a TO performed during RIIO-ET1 and RIIO-ET2. The opposite is true. For example, if we had 20% better performance in prior years the target of 125 becomes 130 MWh. This is the opposite of what Ofgem states that the methodology should do. Equally, if we had 20% worse performance in prior years the target of 125 becomes 121 MWh. So poorer past performance leads to a tighter target.

Therefore, Ofgem cannot therefore rely on this methodology. We support a target that genuinely reflects the reliability improvements achieved during RIIO-ET2, as intended by Ofgem, while recognising that a target of zero or near-zero would encourage inefficient expenditure. Sustaining current levels of performance may be challenging given expected strain on the network as it expands.

In our business plan, we proposed a methodology that aligned with Ofgem's proposed principles but we recognise that its use produces a target that for NGET is higher than the current target and that this may not be acceptable to our stakeholders. We are therefore willing to accept a target of 125 MWh (a 15% reduction on our current RIIO-ET2 target) if additional exclusions and exemptions are included as requested in our business plan. These are for:

- **Events that result in a loss of supply to demand associated with defueling and post defueling nuclear power stations**, where the network assets are solely supplying this type of demand. The impact on the end consumer from a loss of supply is negligible and therefore we consider it should not be classified as an Incentivised Loss of Supply Event. This would avoid TOs investing and prioritising to minimise the likelihood of such events given the negligible impact it would have on consumers. For example, managing down the risk of an Incentivised Loss of Supply Event to Dungeness nuclear power station would require us to invest between £100m to £120m at two substations and an overhead line circuit that will no longer be required once the power station is decommissioned.
- **Events that occur when the network is operated under increased risk to deliver greater system access** that facilitates growth in the network. Taking forward the actions endorsed in the Transmission Acceleration Action Plan (TAAP) to support delivery of network expansion could impact on ENS performance. Design standards set in the Security and Quality of Supply Standard (SQSS) may be modified to provide for a more tailored approach that allows for increased system access. This could have implications for the frequency or magnitude of ENS events. But not being able to operate the

network this way would have wider implications for us being able to carry out all the work necessary to support Government's ambitions. Having the ability to exclude events that may arise in these circumstances will allow us to consider risk holistically and make the appropriate trade-offs rather than taking a risk-averse approach that reduces the risk of ENS events but is not the optimal overall outcome.

To manage financial risk that could be caused by this incentive, we support a collar being implemented. Ofgem has proposed this is set based on -0.38% RoRE, equating to a -£54m collar annually, which is stated as being similar to RIIO-ET2. The current collar is below this value and therefore, even factoring in the growing size of the business, it is not comparable. Based on the current VoLL, to breach the target would require ENS in a year to be above 10,000 MWh. We therefore do not consider that this collar provides any realistic risk protection. A justifiable collar should protect against financial risk that has a low but reasonable probability of occurrence. ENS of 10,000 MWh has no reasonable probability of occurrence. As an alternative, we propose that the incentive impact is collared at -£20m. This would still require performance to be twice as poor as our worst performance in the last 30 years. This provides meaningful protection while remaining unlikely to be breached. We believe it's Ofgem's intention for the collar to be fixed as a £m figure for the duration of the price control. We will feedback to Ofgem's licence consultation which does not currently deliver on this intention.

Ofgem's alternative methodology results in a target that is 85% lower than the target in the current price control. This scale of reduction in target does not reflect Ofgem's position that keeping incidents of energy not supplied low is getting harder. We would not accept such a target and consider that, as a larger network, it is not justifiable to expect us to meet a lower target than other TOs.

Ofgem has also suggested linking the issue of setting a value of lost load (VoLL) with setting the target. It states "*Methodology 1 [target of 22 MWh for NGET] remains an open proposition for us if the VoLL figure comes out at a level far above its existing level of £21,008 per MWh*". Ofgem's reasoning for taking this position is flawed. The value to consumers (as measured by VoLL) should have no relationship to the target set. It would though increase the risk of financial detriment which cannot be outweighed by other aspects of the price control settlement. We support the use of an updated VoLL figure but this will need to be agreed in Final Determinations. If an update to VoLL is not available for Final Determinations Ofgem must consider either keeping the current figure or ensuring TOs are not exposed to a materially different risk profile through an alternative approach to the financial collar. If Ofgem is concerned about the exposure of consumers to significant rewards were VoLL to be materially larger, this could be resolved through capping the reward. Although we note that VoLL would have to be c. £1.74m for a cap of the same magnitude as the proposed collar to be matched (based on a target of 125 MWh).

By Final Determinations, Ofgem should:

- **adopt a 125 MWh target for NGET with expanded exclusions**
- **implement a fixed -£20m financial collar**

ETQ16. What are your views on our consultation position for the SO:TO incentive approach to BAU enhanced services in ET3?

We fully support the continuation of the SO:TO optimisation incentive, however, we do not support the changes Ofgem is proposing to how eligibility for incentives is assessed as we think they will materially reduce the power of this incentive, to the detriment of consumers.

With constraint costs forecast by the NESO to rise, this incentive will continue to be a very important part of the price control framework given its impact on reducing electricity bills. It has already proven to be an effective incentive, with Ofgem calculating the benefit to consumers as a £266m reduction in bills in first two years of operation.⁴

Given its success to date, we do not support the changes Ofgem is proposing. Ofgem proposes an approach to assessing which actions taken by TOs, through the STCP 11-4 process with NESO, should be eligible for incentive payments and which should not. While we support the principle of Ofgem's position, namely that TOs should not receive a reward for business-as-usual (BAU) activity, we consider that, by their definition, all actions undertaken through STCP 11-4 are enhanced services and not BAU and should therefore qualify for an incentive. It is therefore our view that the proposed decision tree and eligibility criteria should be removed.

We are concerned that the ambiguity of a decision tree, and the ex-post assessment by Ofgem of eligibility, will materially diminish the power of this incentive. This incentive has resulted in material savings to consumers by actions TOs have taken to support NESO manage constraint costs.

The decision tree and proposed process would:

- **Be rigid and lack nuance:** Decision trees, by their nature, are rule-based and can struggle to accommodate complex, ambiguous, or exceptional cases that do not fit neatly into predefined categories. This inflexibility will lead to incorrect rejections and/or forced approvals that do not fully align with the spirit of eligibility.
- **Create a time-consuming pre- or post-approval process:** Requiring detailed pre-event eligibility checks or enhanced reporting for every enhanced service provided would create significant administrative burden for both TOs and Ofgem.
- **Discourage innovation and adaptability:** If an enhanced service does not fit the strict criteria, there is a disincentive to consider its potential value, stifling innovation or flexibility in service planning.
- **Create the potential for gaming:** There could be opportunity to manipulate information to fit the decision tree criteria, rather than focusing on the genuine justification.
- **Limit learning and feedback loops:** The binary yes/no outcome of a decision tree provides limited insight into why an action was deemed eligible or not, making it harder to refine policies over time based on real-world scenarios.

We invest time and resource in delivering positive outcomes for consumers through the STCP 11-4 process. Such resource is less likely to be available if there is uncertainty on what value these actions drive for the business.

While, the STCP 11-4 process allows for recovery of the cost of actions, it does not appropriately cover the broader costs of prioritising time, resource and management attention needed to drive innovation in our approach. The incentive is what enables this investment.

We have assessed previous and potential actions against the decision tree criteria and found many cases where eligibility is unclear due to the format and drafting of the decision tree.. For example, sensor based DLR, which we understand Ofgem is supportive of, may not meet the current definition to "physically enhance an asset". We provided additional examples in information shared with Ofgem on 1 August 2025.

If Ofgem remain minded to include eligibility criteria rather than treat all STCP 11-4 enhanced services as applicable, improvements are needed to the envisaged process and definitions. We recommend:

- **Principles based rules for eligibility:** Rules, rather than a decision tree, will be simpler to follow. The proposed rules build on the previous feedback we provided (ahead of the Draft Determination) on definitions within the decision tree. These rules should be:
 - Does the enhanced service result in a change in the **design or delivery methodology** from what has been funded? Defined as: the approach planned for the delivery of works to our assets including both investment in new assets and maintenance of existing assets.

⁴ Ofgem, Sector Specific Methodology Decision Electricity Transmission Annex

- Does the enhanced service **physically enhance or modify an asset**? Defined as: where the TO upgrades or adds something to an asset beyond its current operating mode or makes modifications to network configuration.
- Does the enhanced service increase the risk of operating an asset outside of its **standard technical limits**? Defined as: technical limits, including but not limited to, those specified within business technical specification documents; manufacturers recommended specifications; industry recognised specification, e.g. Energy Network Association (ENA) Technical Specification, British Standards Institution (BSI) Technical Specifications.
- Does the enhanced service provide **operational flexibility beyond standard network operating policy**? Defined as: the ability to respond to changes in power flow while maintaining reliability and stability. For example, increasing the capacity to handle variability; increasing power flow management capability; increasing resilience to disruption and faults.
- **Presumption of eligibility based on agreed rules**: TOs will assess proposed new solutions against the eligibility rules. This places the responsibility for demonstrating eligibility directly on TOs, fostering a more thoughtful and responsible approach.
- **Annual reporting of enhanced services against eligibility rules**: Using a simple template to provide Ofgem with information on how new solutions have met one or more of the eligibility rules.
- **Reporting from Ofgem of concerns post annual review**: Instances where justifications are weak, unclear, or do not align with the spirit of eligibility would trigger discussions, guidance, and potential policy refinements, e.g. lists of future ineligible services. Ofgem could choose (based on its position of favouring self-reporting) the level of depth at which to carry out this review.

Please see supporting document NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives

By Final Determinations, Ofgem should treat all actions undertaken through the codified STCP 11-4 process between TOs and NESO as enhanced services, not BAU, and therefore all eligible for the SO:TO optimisation incentive

ETQ17. Do you agree with our proposal to introduce a clawback mechanism in the SO:TO ODI-F for enhanced services requested that are unfulfilled?

We agree with the principle of a clawback mechanism for situations where TOs have acted against the interests of consumers in preventing a suitable action taking place on their network that would have reduced constraint costs. However, while we support the intent, we cannot endorse Ofgem's current position due to the lack of clarity and detail around the mechanism's design and the potential risks it may introduce.

Despite supporting the principle, we cannot yet support the mechanism as proposed. The Draft Determination does not provide sufficient information to assess its overall merit or the potential risks it may pose to TO financeability. Ofgem has acknowledged the need for further discussion with TOs and NESO, and we welcome the opportunity to engage constructively.

The following key issues must be addressed and further clarity should be provided ahead of Final Determinations:

- **The definition of qualifying circumstances** - the definition of qualifying circumstances must be clearly articulated. There are legitimate reasons why a TO may need to reject a NESO request, and it is challenging to define when such a rejection is unreasonable. The mechanism should only apply where the TO had a viable choice and opted not to fulfil a NESO request. It must exclude cases where NESO did not provide adequate time for analysis and mobilisation, or where no technically viable solution was available.

In practice, our record demonstrates strong cooperation with NESO. Since April 2021, we have been unable to action fewer than one in ten requests to reduce constraints, and this number has been steadily decreasing. Where we have been unable to meet a request, it has been due to the absence of a technically viable solution for the specified location and time. We consistently respond to the vast majority of NESO requests and often proactively propose constraint cost-saving actions, which NESO is not always able to accept. It would be inappropriate to financially penalise TOs for decisions that were necessary at the time, particularly where those decisions were made to preserve network stability and safety.

- **The scale of the clawback** – we propose that this must be defined ex-ante as a fixed financial value. This would provide transparency and predictability, reducing the risk of disproportionate financial exposure. Historical data on the average value of a SO:TO enhanced service could be used to inform this value.
- **Accountability and reporting responsibilities for both NESO and TOs** – there must be a clear articulation of accountability and reporting responsibilities for both NESO and TOs. Ofgem must clarify who is responsible for determining whether the clawback mechanism should apply and what reporting requirements are necessary to support these decisions. NESO may require additional capabilities to fulfil this role, and the relevant data is not currently collected or audited as standard. New reporting requirements will likely be needed for all parties involved.

Ofgem must provide clear definitions, fixed clawback parameters, and accountability structures ahead of Final Determinations to ensure the mechanism is fair and transparent.

ETQ18. Which of the three options for managing differing approaches between TOs do you think would work most effectively in the SO:TO ODI-F?

We do not support any Ofgem's proposed options for managing differing approaches between TOs. We find the three proposed solutions in Ofgem's Draft Determination unworkable. They do not effectively address the issue of fairness and risk undermining the incentive's core purpose.

We view that differences in how TOs propose to fund their activities should not affect whether enhanced services, recognised and assessed through the STCP 11-4 process, are incentivised. The focus should remain on the value these services deliver to consumers.

We see value in ensuring that TOs are learning from each other, and NESO has an important role to play in facilitating this learning. However, this should not result in a TO being penalised/rewarded for being later/the first in adopting an approach. Network configurations and the specific challenges faced by each TO vary, which naturally leads to different prioritisation of services.

We support Ofgem's position to encourage the use of more dynamic line rating (DLR), given the significant benefits it offers in reducing constraint costs. We are actively progressing with the rollout of sensor based DLR to complement other actions we take to provide NESO with enhanced ratings on our network and thus offer routes to reduce constraints and the costs of managing them.

Ofgem's description of different TO approaches is not accurate and reflective of the evidence. We have chosen a leading-edge approach by rolling out innovative sensor-based technology to provide NESO with enhanced ratings. Our business plan detailed our planned approach over RIIO-ET3 which, if the funding and incentive mechanisms are appropriate, will build the scale and pace at which we are rolling DLR out over RIIO-ET2. Sensor-based DLR builds on our use of weather-based and seasonal provision of enhanced ratings. Based on available information, other GB TOs have not yet reached the point we have in rolling out a sensor-based approach. They have to date focused on providing digital tools to enhance the automation in providing weather-based enhanced ratings. We are also investing to improve the automation of information sharing with NESO to maximise the opportunities available.

Both the proposal covered by this question and the use of eligibility criteria as part of an ex-post review of actions could dampen the focus and speed at which networks would rollout sensor-based DLR, capable of providing enhanced ratings to NESO as a solution to constraint management. **The SO:TO incentive as an effective tool for encouraging TOs to take action and therefore consider its current design should be retained. There is a strong track record of the incentive realising >£266m of savings in the first two years of RIIO-T2.** As noted in our response to ETQ16, the incentive has driven material value for consumers and continues to do so.

Ofgem's concern that has led to its consideration of different incentivisation options is around fairness of different treatments. While we do not agree there is any evidence for this concern, we have assessed Ofgem's options. However, none of them provides a solution which meets Ofgem's objective of encouraging the use of more DLR:

- **Option 1**, reducing the incentive rate to 5% constraint costs saved: If Ofgem is correct (and we do not consider it is) then this would still be unfair as some TOs would have access to the incentive and others would not. It also reduces the value to a TO of DLR and could have the effect of moving a TO's focus to other enhanced services which may not provide as much consumer value.
- **Option 2**, offering a Business Plan Incentive (BPI) reward: The BPI guidance cannot be retrospectively changed. If Ofgem has taken our approach versus the approach of other TOs into consideration in setting the BPI results then we consider an error may have been made. Ofgem's description of our approach is inaccurate as we have clarified in this response and through engagement. Ofgem may, based on its descriptions in the Draft Determination, have considered that our approach does not demonstrate that we have "proactively planned whole system enhanced services" when we have. This error must be rectified in the Final Determination.
- **Option 3**, removing eligibility for enhanced services that are superseded by the technological advancements: We do not fully understand how this would work and how it would interact with the proposed eligibility decision tree. Our main concern is that it would require significant monitoring and judgement to be applied by Ofgem on what enhanced services are the most innovative and what are the least and what may be justified and unjustified restrictions on their rollout by individual TOs.

We therefore consider Ofgem's three options in the Draft Determination unworkable but believe there is a way forward.

We support Ofgem's position that funding and incentivisation of DLR must be seen to be fair across the TOs. We view that retaining the current approach to incentivisation is fair. To make use of the enhanced ratings that DLR can provide requires engagement between NESO and TOs through the STCP 11-4 process. NESO will still carry out an

assessment before deciding to make use of the enhanced ratings available.

There will therefore be a calculation of constraint costs saved and **all TOs will be eligible to retain 10% of the value when NESO calls on the use of enhanced ratings, irrespective of whether sensor or digital support costs were funded through other routes**. So, we view that all TOs remain incentivised to provide NESO with enhanced ratings under the current approach despite varying approaches to seeking funding.

Ofgem should retain the current SO:TO incentive design in Final Determinations and ensure that all TOs are rewarded based on the value of the enhanced services they deliver, not on how those services were funded.

ETQ19. Do you agree with the need to introduce an Innovative Delivery Incentive to drive the five behaviours that we've identified and do you consider that there are any behaviours that are missing?

We agree with Ofgem introduction of an incentive to support innovation in the delivery of projects, because it will create value for consumers by incentivizing TOs to take risks in deploying new technologies and innovations, where these incentives would otherwise be less strong given the late ex-ante nature of allowance setting and the five year price control horizon.

We have proposed an incentive in our business plan to tackle similar issues noted by Ofgem and have provided a proposed solution for the design of an innovation incentive in the supporting document "NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives".

The late ex-ante nature of allowance-setting and five-year price control horizon reduce the incentive for long-term innovation and cost allowances are not designed to cover the additional risks undertaken by innovating. We also support Ofgem's position that this incentive can create additional transparency around the consumer value provided by innovation. We address this further in response to ETQ21.

Additionally, it is increasingly clear, given the scale of investment necessary over RII0-ET3, that TOs will not be able to deliver what is required by working in the same way as in the past. While aspects of the existing framework support innovation, including incentivisation of delivery timelines and innovation funding schemes to trial new approaches, the framework is limited in its ability to truly encourage a programmatic approach to rolling out 'game-changing' innovations. Existing innovation funding schemes drive material consumer benefit but they were not designed to support programme-level scalable innovation which this incentive could do if designed appropriately.

We support the five behaviours Ofgem has outlined to guide the areas of focus for this incentive which are: savings in supply chain/contracting; innovations in design/engineering; speeding up delivery; collaboration with the NESO on strategic planning and outages; and rollout of innovations trialled via existing innovation funding schemes.

We suggest that, in outlining the value of this incentive to stakeholders, there is also focus on the outcomes that actions and behaviours are driving at delivering, namely: **reducing costs (both at the project and whole-system level), accelerating delivery timelines; and delivering improved environmental or societal outcomes.**

Ofgem must introduce an incentive to support innovation in the delivery of projects. Ofgem should use our proposed solution in our support document as the basis for the incentive, as a more objective approach (which reflects the principles of good incentive design).

ETQ20. What are your views on our proposed design of the Innovative Delivery Incentive?

We do not agree with the proposed design of the Innovative Delivery Incentive, as the design details set out – while high level – would not be sufficient to drive the desired behaviours the incentive is seeking to encourage.

Our main concerns with the incentive as currently proposed are:

- **Value available is based on a subjective assessment:** Ofgem proposes that a panel including themselves, the NESO and one independent expert assesses how well a TO has demonstrated the behaviours and sets the value of the incentive. The subjective nature of this approach, particularly as Ofgem has not yet been clear on the criteria that may be applied, means it is not possible for a TO to ascribe any value to this incentive.
- **An arbitrary financial threshold placed on access to value:** The reasoning for Ofgem's position that an appropriate materiality threshold is £10m per behaviour is not evidenced or explained. We understand the importance of only rewarding TOs where benefits exists, but Ofgem has not presented evidence on why a £10m threshold is appropriate. Ofgem needs to explain and justify the approach that it proposes.
- **There are only two points at which value can be demonstrated, and one falls outside of the RIIO-ET3 period:** Ofgem has confirmed since the publication of the Draft Determinations that the proposed cap of 50-100 basis points on return on regulated equity (RoRE) would be the maximum available across the whole price control period. Both the scale of the value available and the fact that it would only be accessible at one point in the RIIO-ET3 process diminishes the potential for this incentive to deliver on the objective outlined.

Ofgem has stated that *"we do not expect that a low materiality reward under this incentive would achieve the desired behavioural changes"*. We fully support this statement. We have therefore looked at each aspect of the design of this incentive and considered how we can build on Ofgem's proposal to deliver the framework for a material incentive that meets the objectives on which we both agree.

The Draft Determinations explained Ofgem's concerns with a quantitative performance measure and the ability to measure performance robustly. While we consider there is good material available to build a methodology from within the sector and through learning from wider industries, we believe a more objective approach to the incentive could be taken.

We consider that, instead of a qualitative assessment approach, the value of the incentive to a TO should be linked to the value of the benefits demonstrated. TOs would keep a share of the benefits expected from the innovation based on an agreed methodology.

Our proposed design of the innovative delivery incentive, building on the points above, is provided in the table below.

Design parameter	Description
Scope	<ul style="list-style-type: none"> • Early-stage innovative actions/roll-out in design and delivery of projects. • Innovation focused on: reducing system costs, shortening delivery time, delivering better environmental outcomes and/or delivering better societal / community outcomes.
Performance measure	<ul style="list-style-type: none"> • Innovation would demonstrate benefit in one of the following behaviours: supply chain/contracting, design/engineering, speeding up delivery, collaboration with NESO on strategic planning/outages, rollout of NIC/NIA/SIF innovations. • TO produces an annual report quantifying innovations demonstrated in the prior year (e.g. as identified in Project Assessment submissions) and based on agreed methodology. • Panel (including independent technical experts) assures the quantification of benefits.
Target	<ul style="list-style-type: none"> • Annual report produced by the TOs with quantification of benefits for innovations being rolled out. See our response to ETQ21 for further information on methodology for quantification.
Incentive value	<ul style="list-style-type: none"> • Retention of 50% of the forecast net present value (NPV) of the innovation benefits. This would ensure TOs focus on the transformational innovation which provides the greatest consumer benefits and compensates for risk. • Potentially a smaller share of reward for new solutions proven but yet to be fully rolled out.
Financial cap	<ul style="list-style-type: none"> • Cap of 40 bps / per year (aligned to the Distribution System Operator (DSO) incentive power) – and ‘roll-over’ of unused reward.

Engagement between Ofgem, TOs and other stakeholders together with appropriate consultation will be necessary to finalise the detail of the incentive design. This must be completed ahead of the Final Determinations to provide confidence to our stakeholders that this incentive can drive outcomes they value and to our investors to enable them to ascribe a value to this incentive when evaluating the balance of risk and reward within the price control settlement.

Please see supporting document NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives

Ofgem must introduce an incentive to support innovation in the delivery of projects. Ofgem should use our proposed solution in our support document as the basis for the incentive, as a more objective approach (which reflects the principles of good incentive design).

ETQ21. What are your views on how TOs could demonstrate 'consumer value' to justify rewards under the Innovative Delivery Incentive?

It is important that trust is built between stakeholder and TOs by outlining a clear methodology to be used to demonstrate consumer value of the type of innovation being promoted under this incentive. Engagement between Ofgem, TOs and other stakeholder will be necessary to work through the detail of this methodology but we provide some initial thinking in this response.

Benefits of innovation are broader than just savings in the cost of delivery. Therefore we recognise that there are challenges in monetising all the different types of benefit. But we believe these challenges are not insurmountable and there are existing tools and techniques from which TOs and Ofgem can learn.

The following is a high-level methodology aligned to the approach taken on the DSO incentive and with the HMT Green Book:

- **Identify outcomes & theory of change:** Identify the key consumer/societal outcomes/benefits from the innovation and define a 'theory of change' on how the innovation/behaviour achieves these outcomes/benefits.
- **Set counterfactual:** Set out what would have happened in the absence of the innovation (e.g. 'should cost' estimates) and strip out innovation benefits already rewarded through different incentives (e.g. SO:TO).
- **Quantify impacts / outcomes:** Quantify impact of innovation (e.g. reduced costs and/or time, improved quality) vs counterfactual and assess volume of work/projects and time profile over which the innovation applies and extrapolate.
- **Value impacts / outcomes:** Apply monetary value metrics to these impacts (e.g. costs, value of faster delivery, social cost of carbon) aligned to HMT Green Book where available. Then convert stream of estimated / forecast benefits and costs into a net present value. Examples of quantification of benefits include:
 - Constraint and carbon costs savings from delivering earlier than would have been the case without the innovation
 - The societal cost of the carbon saved by taking a less carbon intensive option, e.g. low carbon concrete
 - The economic benefits achieved from jobs created or skills enhanced, e.g. using a new UK based supplier for HVDC cables.
- **Assessment / assurance:** TOs submit an annual report quantifying the benefits of innovations demonstrated in that year which can be assured by a panel with independent technical representation.

Please see supporting document NGET_RII03_ET1-6_ET7_ET16_ET20-21_Incentives

Ofgem should work closely with TOs and other stakeholders together to finalise the detail of the incentive design. We would welcome, in particular, an opportunity to test use cases with Ofgem ahead of finalising the design.

ETQ22. Do you agree with our proposal to introduce the CSNP Co-ordination LO?

We do not agree with the proposed CSNP Co-ordination License Obligation as it is unnecessary. The Licence Obligation will not introduce new roles or responsibilities, which are already in the System Operator Transmission Owner Code (STC), but will introduce a new obligation to adhere to them. We already have a separate License Obligation to adhere to the STC.

For FDs, Ofgem should:

- **Remove the proposal to introduce this Licence Obligation.**
- **Coordinate with other on-going developments, such as the CSNP Guidance document currently under consultation to ensure alignment with requirements across the TOs and NESO.**

We do not agree with the proposed CSNP Co-ordination License Obligation. At best, it is unnecessary and at worst, could cause significant unfairness to the overall framework. For example, based on the current timeline presented by NESO and draft methodology, TOs would have only 6 months from the notification of system requirements to develop options to the end of strategic optioneering. This is overly optimistic and goes against Ofgem's proposal to move to a 3-year planning cycle to allow more time for options development. TOs may also need to provide support to third parties who want to feed proposals into the CSNP, though the scope of that is still unclear, but if that was also within the LO this could become a significant burden/hurdle for TOs to meet.

Additionally, our ability to provide timely and quality inputs is intrinsically linked to the quality and appropriateness of the overall methodology and timelines for the CSNP from NESO, as well as timely inputs from NESO.

ETQ23. What are your views on our consultation position for the LEI UIOLI in RIIO-ET3?

We do not agree with Ofgem's consultation position for the LEI UIOLI in RIIO-ET3 as the proposal currently overlooks key factors that are critical to the success of LEI in RIIO-T3.

Ofgem's proposal does not adequately reflect the financial pressures experienced during RIIO-T2, nor does it account for the rationale behind underutilisation of the allowance in T2 when setting the allowance for T3. Additionally, we consider that the proposed scope the LEI is not broad enough and data requirements are disproportionate to level of expenditure. For these reasons, we do not support the current position and outline our concerns in more detail below.

Cost Assumptions and Inflation

The proposal assumes that costs are anticipated to be consistent across T2 to T3, without accounting for inflationary pressures or anticipated further interest in LEI. Cost pressure have increased throughout the T2 period, as evidenced in our engagements with Ofgem, contradicting the assumption of cost consistency. Furthermore, stakeholders across designated landscapes have also raised concerns that the current cap on individual grants is no longer fit for purpose, particularly in light of inflation. These financial pressures must be acknowledged to ensure the initiative remains viable and impactful in T3.

LEI allowance

Ofgem's decision not to award the requested LEI allowance for T3 was based on low utilisation during T2. However, this does not reflect the underlying cause, stakeholder uncertainty around the initiative's continuation. As noted in section 3.256 of the Draft Determinations, this uncertainty significantly limited engagement and uptake. Since confirming LEI's continuation into T3, we have seen a clear increase in stakeholder interest and momentum. In light of this, we believe the allowance should be reconsidered to reflect current levels of engagement and to ensure the initiative is adequately supported for successful delivery.

Scope and Definition

As previously communicated to Ofgem in February 2025, we view that expanding the scope of LEI would better serve consumer interest. A broader scope would enable projects to drive greater efficiencies and improved value for landscapes. We therefore disagree with the points covered in section 3.253 of the Draft Determinations and we consider that the proposal should be amended to reflect the proposed new definition of LEI communicated in NGET's letter to Ofgem dated 12 February 2025.

Data Requirements

The data collection requirements outlined in section 3.258 of the Draft Determination are considered disproportionate to the level of expenditure involved. We are concerned that these requirements introduce unnecessary complexity and administrative burden which could reduce efficiency and detract from delivery. We recommend that the approach be reviewed to ensure requirements are more proportionate.

Ofgem should approve the original funding request of £15 million, broaden the scope of LEI to drive better outcomes, and reduce the proposed data requirements to ensure proportionality by Final Determinations.

ETQ24. What are your views on the proposed New Infrastructure Stakeholder Engagement Survey ODI-R, including areas of engagement measured, the proposed survey design, the stakeholders targeted, and the proposed reporting format?

We agree with the importance of capturing feedback on our approaches and the benefits of bringing consistency to new infrastructure stakeholder engagement. It is vital that we undertake effective stakeholder engagement to ensure that impacted communities feel actively listened to, and have their views inform project planning. We therefore agree with the proposal to introduce an ODI-R on this topic. However, we do not agree with the current survey methodology, specifically around the design and reporting formats, as previously discussed in working group sessions.

Since the initial outline of Ofgem's proposals in February 2025, there have been a number of working sessions amongst the three TOs to share current best practice and review potential options for a revised T3 ODI-R.

We agree with a number of the aspects outlined by Ofgem, namely the move towards standardising approaches across TOs and the emphasis placed on TOs making efforts to give vulnerable customers a greater voice, and welcome the additional qualitative parts to the satisfaction questions. However, we believe that the design of this survey should be co-created with independent market research experts and ISGs to maximise the effectiveness of feedback collection.

We believe the best methods for capturing feedback consistently and effectively would be a combination of:

1. **Annual survey:** A comprehensive survey sent to a discrete distribution list of stakeholders once a year, with survey questions less based on numerical scores and more Likert-scale based, e.g. 'too frequent -> not frequent enough'. Ofgem should involve a market research expert and a representative of vulnerable groups in the design to increase the effectiveness of the survey.
2. **Post-contact focus groups:** Regular focus groups with those who TOs have interacted with to enable insightful conversations around engagement, accessible off the back of various interactions (e.g. online consultations, town halls). Ofgem should involve market research expert and representative of vulnerable groups to help design the format of the focus group and improve accessibility.

We would welcome clarity on what stakeholder interactions would qualify for inclusion in survey/focus group invitations, given the multiple points of contact for complex schemes with long consultation and engagement periods.

From a reporting angle, we also stress that the reporting framework should be designed to avoid "clickbait" headlines and uncontextualised statistics, which could provoke negative public/media reaction during highly sensitive consultation periods. Whilst we agree with Ofgem's proposal that each TO should publish a standardised two-page report, we don't feel that the publication of a league table is beneficial to the end consumer given the low number of TOs and distinct variation in project scope and location.

Ofgem should revise the design of the New Infrastructure Stakeholder Engagement Survey to make it more effective for generating insight on stakeholder engagement, alongside implementing qualitative focus groups to capture detailed feedback. The surveys and focus groups should be designed alongside ISGs and independent market research experts.

ETQ25. Do you agree with our proposal to retain the APM for RIIO-ET3 in its current form?

We agree that the APM should be retained for RIIO-ET3. However, we do not agree that the APM should be retained in its current form as its effectiveness is limited because it cannot be used alongside Early Construction Funding (ECF) for ASTI projects.

The APM is a critical part of the framework that allows TOs to manage supply chain pressures and accelerate delivery. The need for the APM to help mitigate supply chain constraints that might otherwise threaten delay of TOs' investment plans remains justified. We expect this to be the case over ET3 and beyond. However, its effectiveness is limited as a result of Ofgem's decision to prohibit its use alongside ECF for ASTI projects.

The APM approach allows us to mitigate supply chain pressures, particularly those arising from long lead times. This includes bringing forward procurement activity, building supply chain relationships, booking capacity, pre-ordering and buying in bulk. Ofgem should review the APM eligibility criteria to enable its use APM alongside ECF for ASTI projects as ECF covers a broader scope but is available later. The ability to have the flexibility to use both APM or ECF for ASTI projects enables us to procure truly programmatically and deliver more benefit to consumers by doing so. Current rules force TOs to choose between earlier but limited funding through APM or broader support later via ECF. Allowing both mechanisms with appropriate safeguards would benefit consumers more than restricting projects to being able to use either APM or ECF.

While we recognise the concerns around duplicative funding across the two mechanisms, these can be resolved easily through clear reporting structures. We welcome the opportunity to discuss this further ahead of Final Determinations and work with Ofgem and the rest of the sector on a reporting framework which mitigates risk in order that ASTI projects are able to access both funding regimes in RIIO-ET3.

Given that the APM is a new regulatory funding mechanism introduced in the final year of RIIO-ET2, we would also recommend a review of the mechanism should take place within the ET3 period and once TOs have used the mechanism, tested the APM reporting arrangements and recovered APM allowances. This would enable TOs to feedback on how the mechanism is working, the benefits it is delivering, and allow Ofgem to consider any necessary changes or improvements. We consider that the optimum time for a review would be no earlier than 2028 to allow for thorough testing of the APM.

By Final Determination Ofgem should:

- **change the APM's eligibility criteria and update the APM Governance Document to allow its application alongside ECF for ASTI projects, if necessary, by additional reporting safeguards**
- **commit to a review of the APM mechanism during the T3 period (2028) to allow feedback on how the mechanism is working**

ETQ26. Do you agree with our intended approach to PCF in RIIO-ET3?

We do not agree with the proposed approach for RIIO-T3 Pre-Construction Funding (PCF) because the allowances proposed are too low, do not reflect the expanded scope of PCF activities, and the eligibility for PCF should not be restricted to load-related projects only. The design and workings of the proposal could also be improved.

By Final Determination Ofgem must:

- revise RIIO-T3 PCF funding level substantially above 2.5% taking into consideration evidence shared already, the evidence from the cross-industry proposals that will be presented by the TOs and project forecasts made in forthcoming regulatory submissions
- make RIIO-T3 PCF available for all major projects including those with shared drivers and non-load drivers
- [REDACTED]
- revise maturity requirements for the approval of RIIO-T3 PCF under the Load Reopener as stated in the Eligibility Letter (EL) and align this to other areas of the framework where PCF funding is agreed when need is identified)
- retain the current portfolio style UIOLI mechanism for ASTI projects
- apply the project-by-project approach for the rest of our T3 activities, with supporting mitigations in place to make RIIO-T3 PCF more accessible and flexible widen the reopener trigger to allow TOs as well as the Authority to trigger the re-opener event
- consider our proposals in our paper provided alongside this response “A workable uncertainty mechanism framework”
- update the scope of RIIO-T3 PCF to include equipment not covered by the APM and advanced land purchases; and
- take the opportunity to simplify and establish a workable RIIO-ET3 framework by removing the RIIO-T3 PCF PCD with staged release of allowance.

We acknowledge the ongoing discussions with Ofgem on the level of PCF funding and the opportunity to bring forward a cross-industry view of PCF activities expanded with EEW and strategic land costs. We refer you also to our proposals for a “A workable uncertainty mechanism framework for RIIO-ET3” document, submitted alongside our response to the Draft Determinations, which has relevant supporting information for this question.

Allowances

We do not agree with the proposed position of RIIO-T3 PCF calculated at 2.5% of the forecast total project costs. In March 2025, we provided Ofgem with evidence of pre-construction costs for historic and ‘in-flight’ projects across multiple archetypes (including substations, Overhead Lines, cables, etc.). This showed that the average pre-construction spend (excluding Early Enabling Works (EEW) and Strategic Land costs) varies significantly across various project archetypes and when averaged across all project types is significantly higher than the 2.5% that Ofgem proposed in Draft Determinations. We understand that the evidence was not considered in making the Draft Determination proposals; we believe the outcomes from this work continue to be relevant and must be taken into account when determining percentages for the expanded scope of RIIO-T3 PCF.

Since that time, we have been working with other TOs to develop a cross-industry view of the level of RIIO-T3 PCF and work is in hand to take this forward aligned to latest definitions.

In Ofgem’s Draft Determination, NGET was awarded [REDACTED] as RIIO-T3 PCF baseline allowances. However, the breakdown of this allowance (i.e. PCF allocation) across our RIIO-T3 projects was unclear. We have sought clarification through DDQs ⁵ and welcome Ofgem’s responses and the progress made so far. We will continue to work with Ofgem to understand the breakdown of PCF allowance stated in DD and rectify data inconsistencies together.

Ofgem should revise its PCF funding proposal substantially above 2.5% taking into consideration evidence shared already, evidence from the cross-industry proposals that will be presented by the TOs and evidence we will submit in forthcoming regulatory submissions (covered later in this PCF response)

⁵ NGET 004, 020 and 068

Eligibility

Projects with shared drivers and Non-load Drivers

We do not agree with the proposals on eligibility for RIIO-T3 PCF. Based on conventional definitions of PCF in existing frameworks, PCF is effectively accelerated Closely Associated Indirect (CAI) funding released to support the development of capital intensive, major projects to be ready for Project/Cost Assessment.

The stated position in the draft determination is that load-related projects will be eligible for RIIO-T3 PCF as will those which are predominantly driven by load, and projects with shared drivers and non-load drivers will not. Ofgem further state that other funding mechanisms are available for Non-Load projects. The SSMD recognised that there would be projects where the drivers would be shared and went further to provide a definition and the potential benefits of this approach⁶.

We believe it would be in the best interests of consumers to treat projects with shared and non-load drivers in a consistent manner to those with load-related investments. Similarly, we do not see a route to access development funding for shared driver projects in the case where the load driver falls away due to factors such as evolving network needs and outcomes of strategic planning activities.

Ofgem will be aware that our Business Plan contains significant investments with shared and non-load drivers that meet the materiality threshold of £25m (stated as applicable to load-related projects). These projects are major investments and are often related to “whole site strategies” and or major cable strategies and are not covered by other funding routes such as NARM. We believe it would be in the best interests of consumers to treat projects with shared drivers and non-load drivers in a consistent manner to load-related investments and allow the benefits of PCF to accelerate all our critical investments.

Customer Connections - Portfolio EJP

As part of our Business Plan, we submitted the Customer Connections portfolio EJP. Our objective in outlining the potential for these investments was to share early thinking with stakeholders, (including Ofgem), the supply chain and planners of the system. This portfolio of substation investments shows where there are drivers to invest but the project development is at very low maturity due to the timing of connections.

While the investments covered in this EJP have a need for investment, there is a higher degree of uncertainty than would otherwise be the case as a result of the implementation of Connections Reform coupled with Clean Power 2030 planning. However, we believe there is a need to develop these projects further (or similar ones if needs change) to avoid delaying the connection of clean energy customers.

Our view remains that further project development is necessary, and we requested a UIOLI pot of early development funding to carry out pre-construction activities across a portfolio of ■■■ substation investments up to the point of a re-opener submission via the Load Reopener. This approach allowed us to:

- a) signal to stakeholders and the supply chain and plan for the scale of investment needed over the RIIO-T3 period to deliver the Holistic Transition pathway to net zero;
- b) mitigate customer uncertainty through the creation of connection options that provide future capacity and flexibility to changing customer requirements; and
- c) ensure consumer value safeguards remain in place by providing Ofgem regulatory oversight.

In the Draft Determinations, Ofgem did not support the needs case for this portfolio of activity. We believe that it is our obligation as a forward-looking Transmission Owner, to develop a portfolio of such sites to avoid delaying the connection of clean energy and demand customers closely linked to the country's economic growth.

In order to make the framework workable and less complex, Ofgem must make RIIO-T3 PCF available for all major projects including those with shared drivers and non-load drivers.

To recognise the impact of higher levels of uncertainty caused by Connections Reform and to allow strategic investments where the need for investment is identified, Ofgem should provide early development funding for low maturity connection driven projects set out in the “CC Portfolio EJP”.

⁶ Shared driver projects could include a project that has a load driver (e.g. new generators needing to connect to a substation), where the TO could at the same time upgrade or replace related assets on the same site (e.g. static compensators) that will soon need to be upgraded due to asset health. Completing these works at the same time can offer cost and time savings as compared to waiting for a new outage slot for the secondary piece of work

Maturity Requirements for the release of RIIO-T3 PCF Funding

We do not agree with the maturity requirements for the approval of RIIO-T3 PCF under the Load Reopener as proposed in DD. In the current design, when the Eligibility Letter (EL) is approved, RIIO-T3 PCF is awarded for a project. The EL, as proposed in DD, must cover full needs case and system design and also a level of optioneering (short-list of options, preferred solution and rationale). These maturity requirements mean that a substantial level of project development will take place prior to the submission of EL and subsequent award of RIIO-T3 PCF. This requires TOs to commit to a higher level of spend without regulatory/funding certainty. This is inconsistent with the maturity requirements under CSNP-F framework where PCF is awarded when the CSNP identifies a project as being needed.

The lack of consistency in maturity requirements introduces further (and unnecessary) complexity in the framework where a different driver at the onset leads to very different framework pathways despite the actual nature of the project/investment remaining the same. Either PCF should be granted earlier (c.f. CSNP-F) or an initial allowance should be granted to cover early development costs (c.f. tCSNP2). We see this as a good opportunity to simplify framework where possible.

Ofgem should ensure consistency across various frameworks by releasing PCF at the point of agreeing the needs case

Project-by-project allocation of RIIO-T3 PCF

Ofgem should retain the flexibility of the UIOLI mechanism for PCF under the ASTI framework that is already operational.

The wider approach to funding for ASTI projects differs from that proposed for T3, for example due to the availability of ECF. Maintaining the current portfolio UIOLI approach will allow us the confidence and the flexibility to continue progress at pace across the ASTI portfolio.

The DD ET Annex proposes to allocate RIIO-T3 PCF on a project-by-project basis. For non-ASTI projects, we agree to a project-by-project mechanism for the remainder of our T3 work where PCF would apply as long as mitigations are put in place to make RIIO-T3 PCF more accessible and flexible.

For the remainder of our RIIO-T3 programme the situation is more complex with greater number of projects and increased volatility across and within the portfolio of activities. For this work we now believe that a project-by-project approach brings greater consumer benefit providing greater clarity of funding and consequent reductions in the potential for delays during reopener cost assessments. We note also that protections already exist at the project assessment stage to check and balance efficient spend beyond the agreed percentages.

Ofgem must put in place measures to retain the flexibility of the portfolio style UIOLI mechanism for ASTI projects and apply the project-by-project approach for the rest of our T3 activities but with some adjustments to make RIIO-PCF funding more flexible and accessible

PCF reopener

A PCF reopener is essential, particularly considering the expansion of the definition of RIIO-T3 PCF and the proposal to agree the initial percentage allowed. We believe a reopener is essential to accommodate well-justified cost increases beyond a fixed pre-agreed percentage. However, we do not agree that it should be triggered by the Authority alone. TOs should also have the ability to trigger the reopener as we adapt to evolving project needs (e.g. cost increases from the market/supply chain, evolution of cost, scope, customer needs, increased complexity and; or pace required to completion).

Ofgem must widen the PCF reopener trigger to allow TOs as well as the Authority to trigger the re-opener event

Scope

We note the intention to expand the scope of RIIO-T3 PCF to include Early Enabling Works (EEW). Expanding the definition of RIIO-T3 PCF to include EEW would mean a higher volume of works being covered in the pre-construction phase. Our recent experience suggests that there would need to be a very significant uplift in the PCF percentage to accommodate these activities.

In the draft determination, we note the intention to put in place a fixed percentage for PCF which will now include EEW. Whilst our preferred position is to avoid a fixed percentage that includes EEW costs due to their inherent variability and volatility, we note the direction of travel. It is for this reason we believe it is important to bring to Ofgem's attention the causes of some of this variability and volatility so that there is early recognition of this position before re-opener activities are considered and way in advance of project cost assessment.

EEW vary significantly based on the project and the location of works, e.g. a difficult to access site could need solutions such as culverts and bridges that are more than standard temporary/permanent roads. Similarly, predicting these costs with a high degree of certainty in early stages of the development process is difficult, for example, an OHL solution could be relatively straightforward with limited EEW if it connects into existing infrastructure in easy to access locations but equally the percentage of EEW could be very high if in case of new OHL or cable routes across difficult terrain. EEW activities are aimed at accelerating projects towards the construction phase and may not necessarily need to be deployed for each project or in the same way across projects depending on the acceleration required. Delivering these works early avoids risk being compounded in the construction phase (to the detriment of the consumers) and ensures long-term benefit from efficient delivery of projects.

[REDACTED]

- the **magnitude** of the costs that could be incurred (35%) from recent examples
- their **variability** of these costs between solutions
- their **predictability** is difficult at the start of the development process given supply chain constraints

Given the materiality of these costs drawn from recent experience, keeping expanded RIIO-T3 PCF levels at 2.5% would significantly increase the funding risk to us and when viewed across our portfolio of activities and will add to overall level of risk we hold across the business; we refer you to our proposal submitted alongside this DD response for "A workable uncertainty mechanism framework for RIIO-ET3" where some of these highlighted issues could be covered.

Ofgem should consider our proposals in our paper provided alongside this response "A workable uncertainty mechanism framework"

The Advanced Procurement Mechanism (APM) covers funding for the reservation of factory slots for long-lead items (capped at 20% of equipment cost paid as a deposit for booking a factory slot). This enables procurement at short notice, for a pre-determined list of assets (where procurement is fungible, flexible or bespoke) without requesting approval from Ofgem. Some equipment such as STATCOMs have long-lead times, their costs when scaled up across our RIIO-T3 plan are material, and the procurement is be-spoke in nature as they need to be designed for specific projects/investments. For these assets we are required to make early commitments which are not covered by PCF or the APM.

Similarly, we are exposed to the risks of early land purchases. [REDACTED]

[REDACTED]

[REDACTED]

This is a material issue. When viewed in the context of the overall plans and the layering of risk this will expose TOs to uncertainty which will slow down development at pace. The benefits of accelerated delivery have been recognised in the approach Ofgem has taken under the ASTI framework.

Ofgem must update the scope of RIIO-T3 PCF to include equipment not covered by the APM and advanced land purchases, or provide an alternative mechanism to do so.

Assessment for the release of RIIO-T3 PCF

We do not agree with the proposed updated structure for how RIIO-T3 PCF allowances would be released as set out in the DD, which could inhibit the ability of TOs to progress projects at pace and could put Ofgem approvals on the critical path.

We do not agree with the staged release of RIIO-T3 PCF due to the volume of RIIO-ET3 investments requiring RIIO-T3 PCF as well as the applicability of this mechanism to non-ASTI investments, because of the different features of the investment types:

- a) **Suitability to RIIO-ET3 projects:** The format of staged release of PCF is more suited to the very large new build schemes within ASTI framework which have material planning/consenting requirements as major project milestones and a high level of regulatory certainty that the schemes will proceed.
- b) **Lower regulatory certainty:** Although Ofgem's decision on the EL will provide a preliminary level of PCF certainty on a project, the proposed staged release of RIIO-T3 PCF would leave licensees exposed to higher spending without funding certainty until mature stages of a project – e.g. we would not receive 60% of efficiently incurred PCF spend until fully market tested prices are available and the project ready for regulatory project assessment. This staged release defeats the purpose of upfront development funding to ensure projects are developed at pace. We note also that protections already exist at the project assessment stage to check and balance efficient spend beyond the agreed percentages. The approach risks slowing down the development of projects as regulatory approvals are secured.

We propose that the approval of the Eligibility Letter is used to provide initial funding certainty for RIIO-T3 PCF, any adjustments facilitated by PCF reopener such that there is funding certainty until Ofgem provides its determination on Project Assessment for each project going through the reopener process.

Ofgem should simplify and establish a workable RIIO-ET3 framework by removing the staged release of RIIO-T3 PCF allowances and instead use the approval of Eligibility Letter (with revised maturity requirements implemented) for a project to provide initial funding certainty for RIIO-T3 PCF to a pre-agreed % of project costs. The funding certainty should enable TOs to cover development costs for a project until the determination of Project Assessment.

ETQ27. Do you agree with our updated definition of EEW?

We agree with the provision of a definition of EEW but further improvements should be made. To provide regulatory certainty the non-exhaustive list should be expanded to include; Surveys and Archaeological work, works to manage and mitigate environmental impacts, Logistics in support of early ordering of equipment, discharge of site-specific consents, programme and project management costs. Given the desire to set a fixed percentage for PCF (which includes EEW costs), Ofgem should ensure there is flexibility in regulatory processes to address the inherent variability of EEW needs across our projects.

By Final determination Ofgem should:

- update the non-exhaustive list of EEW activities to include Surveys and Archaeological work, works to manage and mitigate environmental impacts, Logistics in support of early ordering of equipment, discharge of site-specific consents, programme and project management costs.
- ensure there is flexibility in regulatory processes to address the inherent variability of EEW needs across our projects by:
 - i. allocating a higher percentage beyond the pre-agreed percentage for RIIO-T3 PCF at the Eligibility Letter stage should the project forecasting highlight the need and the resulting increased spend for EEW.
 - ii. provide the necessary uplifts to the RIIO-T3 PCF percentage through a PCF re-opener to account for the variability and volatility of EEW, noting that for some projects the uplift may be substantial, not incremental.
 - iii. Giving due consideration at project assessment stage to the variability and volatility of EEW costs and how this could impact the overall project costs, while making judgements on efficient spend

Definition

We agree with Ofgem's statement that EEW does not have a consistent definition in existing regulatory frameworks. We welcome the additional clarity provided by the high-level definition for EEW for RIIO-ET3 as set out in the Draft Determinations and the indicative, but non-exhaustive list of activities included in EEW.

We note that an amended definition of Pre Construction Funding has been included in the initial licence consultation published on 30 July 2025 which includes EEW.

EEW list of activities

There are a number of activities which we see as potentially costly and time consuming and should be added to the non-exhaustive list of EEW. Undertaking these works early can in some circumstances result in significant time and efficiency savings in project delivery with commensurate benefit to consumers. These activities are:

- Surveys and Archaeological work; whilst surveys are required for consenting and design of works, more detailed surveys and archaeological works may also be required prior to construction.
- Works to manage or mitigate environment and nature (e.g. protected species); environmental interventions can be time consuming and may be restricted to particular times of year.
- Logistics. Early ordering of equipment to derisk delivery in light of stretched global supply chains will mean it is necessary to take deliveries at an earlier date, requiring logistics to be established early.
- The discharge of consents requirements (which will be site specific), including local sourcing requirements for Biodiversity Net Gain. This is often required before work can start on site and may only be possible at certain times of the year.
- The additional programme and project management costs necessary to enable other permitted EEW.

We note that the list of activities for EEW presented in the draft determination is presented as a non-exhaustive list; we support keeping the list non-exhaustive. To provide regulatory certainty, Ofgem should agree the addition of above EEW costs categories to the list of EEW activities outline in draft determination.

Regulatory Flexibility

The value of EEW is highly variable and unpredictable in early stages and between projects. As such, **we do not agree with the Ofgem's proposal to put in place a fixed percentage adjustment to RIIO-T3 PCF to take account of EEW.** We set our position in more detail in ETQ26.

If Ofgem implement such an approach it is important that the percentage is set a level that reflects the evidence on the costs of EEW. We are working with other TOs to develop proposals for an appropriate percentage number for RIIO-T3 PCF expanded with EEW.

We also propose an additional approach, given the volatility of the cost levels as the variability between projects will mean fixed percentages are unlikely to be representative of actual requirements.

Our proposal is to provide flexibility at each stage of the regulatory process to recognise the underlying characteristics of specific projects:

- **At Eligibility Letter (EL) stage:** allocating higher percentage for the expanded scope of RIIO-T3 PCF should the project forecasting highlight the need and associated increased spend for EEW.
- **Between EL and Project Assessment stages:** allow PCF reopener to be triggered by the licensees, acknowledging that in some cases the uplift required would be substantial. It would be preferable for the reopener mechanism to account for the significant differences in underlying consumer value and risk driven by EEW and other forms of ECF spend.
- **At Project Assessment:** Take into account the inherent variability and increases that can occur in PCF spending while making judgements on efficient spend

Ofgem should ensure there is flexibility in regulatory processes to address the inherent variability of EEW needs across our projects by:

- **allocating a higher percentage beyond the pre-agreed percentage for RIIO-T3 PCF at the Eligibility Letter stage should the project forecasting highlight the need and the resulting increased spend for EEW.**
- **provide the necessary uplifts to the RIIO-T3 PCF percentage through a PCF re-opener to account for the variability and volatility of EEW, noting that for some projects the uplift may be substantial, not incremental.**
- **Giving due consideration at project assessment stage to the variability and volatility of EEW costs and how this could impact the overall project costs, while making judgements on efficient spend**

ETQ28. Do you agree with our proposed approach to PCF on tCSNP2 projects?

We agree to the proposed approach to PCF on tCSNP2 projects provided that the current timelines for tCSNP2 Refresh outputs hold to June 2026. However, we cannot provide a firm view on the applicability and effectiveness of the overall framework specifically for tCSNP2 projects without clarity on which funding track will apply, and how the specific elements of each funding track would work in practice.

By Final Determination Ofgem must:

- **Establish the process for funding in the event of further delays to the NESO tCSNP2 Refresh. In particular, clarity is required on funding across the Development and Small/Medium track projects to maintain momentum on progression in the consumer interest.**
- **Agree the funding position for the more mature projects in the tCSNP2 portfolio () to ensure alignment on the need to progress these projects at pace ahead of the tCSNP2 Refresh.**
- **Update the PCF amounts and the PCF PCD dates for the Delivery Track projects to ensure these reflect the appropriate scope, schedules and costs.**
- **Provide a greater level of detail on how proposed T3 funding tracks are intended to apply to the tCSNP2 projects.**
- **Outline an approach to setting Target Delivery Dates which must take into account factors like deliverability and wider system needs as set out in the response to ETQ2**

The three tracks that currently make up the tCSNP2 portfolio (Delivery, Development and Small/Medium) will be discussed in further detailed below; we first our general observations.

We agree to the proposed approach to PCF on the tCSNP2 projects, provided the current timelines hold for the tCSNP2 Refresh outputs. These are currently due to be published by the NESO in June 2026. However, if there are further delays to the tCSNP2 Refresh outputs, it will be increasingly challenging to progress efficiently without more specific funding as projects proceed to more advanced activities, longer-term contracts and decision milestones. In summary, further delay to the Refresh will create an unacceptable funding risk.

We have regular engagement with Ofgem on the tCSNP2 portfolio to ensure ongoing alignment on the appropriate activities and funding to maintain progress ahead of the Refresh outputs in June 2026. To link up our current challenges with tCSNP2 and this upcoming T3 price control period, we want to ensure we maintain this ongoing alignment, which is particularly important for our more advanced (). We will continue to provide Ofgem with updated information on the scope, costs and schedules of the Delivery Track projects.

In addition to our response on ETQ2, any approach to setting Target Delivery Dates (TDD) must take into account factors like deliverability and wider system needs. The methodology must ensure that the approach to setting TDDs is based not just on what is economically optimal, but what is deliverable under reasonable assumptions.

In terms of the funding tracks in T3 for the tCSNP2 portfolio, greater clarity on Ofgem's thinking about where these projects will go would be welcome. Our views on the proposed funding mechanisms are discussed further in ETQ 37 and 38.

Ofgem must outline an approach to setting Target Delivery Dates which must take into account factors like deliverability and wider system needs as set out in the response to ETQ2

Ofgem must provide a greater level of detail on how proposed T3 funding tracks are intended to apply to the tCSNP2 projects

Delivery Track

NGET have highlighted to Ofgem in our consultation response on the tCSNP2 licence conditions that PCF amounts and PCD dates currently reflected are not an accurate reflection of projects' current scope and costs. Dates and PCF values in Special Condition 3.45 are based on information that was submitted to Ofgem in November 2023. These inputs to the tCSNP2 exercise were at a very low maturity, and since that time the projects have changed. The draft determination proposals highlight that these projects will ultimately be transferred into the prevailing RII0-ET3 PCF definition following Final Determinations.

Ofgem must update the PCF amounts and the PCF PCD dates for the Delivery Track projects to ensure these reflect the appropriate scope, schedules and costs.

Our views on the proposed PCF framework are set out in responses to ETQ26 and 27, and apply equally to tCSNP2 projects

Development Track

We agree with the position for PCF for tCSNP2 projects that Ofgem has proposed provided that the current time-lines for tCSNP2 Refresh outputs hold to June 2026. The current timelines suggest tCSNP2 Refresh outputs will be published in June 2026, which would be an acceptable amount of time to fund projects based on the broad comfort Ofgem has provided in the T3 DD and tCNSP2 licence decision.

However, if there are further delays to the tCSNP2 Refresh output, it will be challenging to progress efficiently without more specific funding as projects proceed to more advanced activities, longer-term contracts and decision milestones. This is especially an issue for some specific projects in the tCSNP2 portfolio that are significantly more advanced and require more expensive activities to maintain progress ([REDACTED]). This means that Ofgem's suggestion that this approach to PCF and early development funding is "proportionate for the low materiality of spend required" is not accurate for all projects.

Our views on the proposed PCF framework are set out in responses to ETQs 26 and 27, and apply equally to these tCSNP2 projects

Small and Medium Track

For Small/Medium Track projects, there is currently no regulatory funding, and these projects will have to apply for it in T3. The challenges of ongoing spend at risk without clarity on outcomes, adds to risks associated with unfunded projects and would be exacerbated further with subsequent delays to the tCSNP2 Refresh.

Our views on the proposed PCF framework are set out in responses to ETQs 26 and 27, and apply equally to these tCSNP2 projects

ETQ29. Do you agree with our proposed scope, re-opener windows and materiality threshold for the Load Re-opener?

We do not agree with the current proposed scope, re-opener windows, and materiality threshold for the Load Re-opener.

We do not agree that the broader design of the Load framework, including the Load Re-opener, is agile or efficient enough to enable the pace of delivery needed to support the volume of investments required during the next price control.

Ofgem should implement the proposals set out in our Workable Framework paper, as an alternative to framework set out in the Draft Determination

The purpose of the supplementary information paper is to set out a proposal for a such a streamlined and agile framework that would achieve Ofgem's overall objective for the RIIO-T3 framework to "*implement a regulatory framework for energy networks that will help GB accelerate its transition to a clean power system by 2030*".^[1] The paper contains practical suggestions for implementing a workable framework that will benefit consumers by enabling Transmission Owners to deliver their plans at pace and realise the associated benefits.

Please see supporting document NGET_RIIO3_ETQ29_Workable Framework Paper.

In this answer we have referred to the relevant elements of the workable framework proposal and highlighted where they would be implemented across the following areas:

- Scope of reopener
- UIOLI materiality threshold
- Re-opener submission windows
- Review timescales
- Use of licence obligations
- Use of Independent Technical Advisor
- Approach to Project Assessment

We also have considered other interrelated aspects including: Ofgem's review timescales, Licence Obligations, the Independent Technical Advisor and key principles of the Project Assessment submission. Our response details the minimum amendments that would be necessary to enable workable solution for the Load re-opener should broader reforms aimed at enhancing the overall workability of the framework not be pursued.

Scope of Re-opener

We do not agree with the scope of the Load Re-opener which currently excludes projects with a Non-Load only driver (to go through a separate non-load reopener) and other NESO network plan driven projects (to go through the separate CSNP-F reopener). Multiple re-openers following largely identical processes add significant complexity to an already complex framework which we believe could become a blocker to deliver at pace and risks complicating projects with shared or complex driver cases. On grounds of this similarity, a single re-opener mechanism agnostic of driver is both preferable and achievable.

Key differences in the features of Ofgem's proposed re-openers, such as differing consumer protections (PCDs & LOs), deviations in process steps (streamlining without a Needs Case submission), and incentives (timely delivery) for example, can be determined case-by-case basis through collaborative engagement during the initial stages, such as the Eligibility Letter stage, of the re-opener. More details about our proposal, including how it will practically operate, for a single re-opener are included in the Workable Framework paper provided alongside our consultation response.

Ofgem needs to create a unified re-opener which caters for all investments regardless of driver, including Non-Load, shared driver and NESO driven projects.

^[1] RIIO-3 Draft Determinations Overview Document, page 8.

Materiality Threshold

We disagree with the £25m Materiality Threshold proposed for the Load Re-opener and believe this value should increase, at minimum, to £50m – please refer to our response to ETQ31. When pace of delivery and simplification of the framework is critical, a £25m threshold would cause too many low materiality projects to undergo a time consuming and resource intensive re-opener assessment – without providing a commensurate level of protection for consumers.

Ofgem needs to increase the materiality threshold to £50m based on our analysis included in ETQ31.

Re-opener Submission Windows

We do not agree with the proposal to have two re-opener windows in April and October each year. This should be replaced by a monthly submission date on which TOs can submit Needs Case and Project Assessments. Enabling the process to be more responsive to project delivery and minimising the risk of delays resulting from the regulatory process. We agree with Ofgem's position that Eligibility Letters can be submitted at any time, following 1 month notice. The reasons for our concerns include:

- Despite TOs' best planning efforts, change is a regular aspect of investments which can affect intentional timescales and third-party involvement may not align with intended regulatory schedules - a project could be delayed up to six months if a delay caused a submission window to be missed.
- Ofgem's review timeline is central to the effectiveness of bi-annual submission windows. Projects may be held up with Ofgem and unable to progress as intended via upcoming submission windows if the proposed 6-month review period is exceeded (as regularly experienced in RIIO-T2).
- We are unclear how the annual April APM re-opener window and Ofgem determination timeline align with the bi-annual Load Re-opener submission windows. Delays in APM outcomes may impact the availability of information needed to develop Needs Case and Project Assessments for submission.
- Given that the T2 LOTI process features submission windows without restrictions, we are concerned that the framework is becoming less agile over time, even as agility and flexibility have become increasingly important.

In view of the significant investment involved, we acknowledge that any expected delays may collectively have a substantial impact on our capacity to meet CP2030 objectives, potentially resulting in notable consumer detriment. While it is important to sustain delivery momentum during this period, we are increasingly aware of the risks associated with advancing project delivery in the absence of regulatory approval. We are concerned that, if experienced across multiple investments, these cumulative impacts may result in National Grid, as a responsible business, being unable to commit significant financial resources to projects without regulatory certainty.

Ofgem needs to introduce monthly submission windows for all Needs Case & Project Assessment submissions.

Review Timescales

We do not agree with the respective three and six month review timescales for the Eligibility Letter and Needs Case/Project Assessment submissions for the Load re-opener, and the lack of assurance provided for meeting these timescales. We would need at minimum for these timescales to be reduced to two months and for such timescales to be committed to by Ofgem.

Our RIIO-T2 experience indicates that re-opener assessments have typically taken an average of 12 months to achieve a decision. Prolonged determination periods postpone investment delivery and present challenges for ongoing investment planning, especially when progress decisions rely on regulatory certainty.

Accordingly, Ofgem should implement Service Level Agreements (SLAs) for their review timescales with a 'stop-the-clock' mechanism for their effective management - administered under an refreshed approach to governance and a joint management of the pipeline, as outlined in the Workable Framework paper submitted with our consultation response. A further summary is provided below:

- **SLAs** - SLAs provide confidence and clarity to TOs, allowing them to sufficiently plan for interdependent project delivery and regulatory processes.
- **A 'stop-the-clock' mechanism** – The information TOs provide is critical in facilitating Ofgem's timely review of a submission. Accordingly, if Ofgem requests information that should have reasonably been included as per re-opener guidance, the SLA may be paused and restarted from when the request is made and fulfilled,

respectively.

- **Improved governance and pipeline management** - We have outlined an improved approach to governance and jointly managing the pipeline in the Workable Framework paper accompanying this response. This approach would facilitate management of the substantial investment pipeline through regular meetings to monitor progress and address challenges collaboratively. Bilateral monitoring of investments sat between TOs and Ofgem, including managing SLAs and stop-the-clock mechanism would feature in this forum.

Ofgem needs to reduce timescales taken to review submissions to 2 months for all submissions and establish an SLA and 'stop-the-clock' mechanism to guarantee these timescales.

Use of Licence Obligations

We do not agree with the proposal to set Licence Obligations (LOs) in addition to Price Control Deliverables (PCDs) as an outcome of all Load re-opener investments in RIIO-T3. Considering the volume and wide-ranging value of pipeline investments and our experience of changing dates for LOs in T2, this approach introduces considerable complexity and regulatory burden to the framework's administration, while failing to deliver commensurate consumer protection in all cases.

While we agree that PCDs should be applicable to all investments, our position on the application of application of LOs is dependent on Ofgem's views on our proposed funding framework:

- **Subject to Ofgem supporting the establishment of a reopener mechanism agnostic of driver, LOs should be employed judiciously for non-CSNP investments on a case-by-case basis.**
 - This would be based on whether a project (1) holds strategic importance, such as possessing Government endorsement or CP2030 designation (2) a reliable methodology for establishing an appropriate delivery date can be identified (3) there would be significant consumer detriment in the event of delayed completion.
 - In such cases the LO date should not be set before the Project Assessment submission. A definitive delivery date cannot be determined for a project until Gate C is completed, as this stage incorporates full supply chain input.
- **If Ofgem do not support our request to modify the re-opener to be driver agnostic and the current proposed Load re-opener remains in effect, we do not agree that LOs should be applied to all non-CSNP projects.**
 - The basis for setting LO dates for non-CSNP projects would be within the remit of the TO, compared to being underpinned by independent body, such as for NESO driven projects like the CSNP. In absence of any timely deliver incentive for non-CSNP to encourage delivery as early as possible, the blanket introduction of LOs presents only a downside risk for TOs, which may inadvertently encourage perverse behaviour to set any target delivery date as late as possible.
 - There is inconsistency in Ofgem's application of LOs and PCDs to pipeline investments but only PCDs to baseline investments. Baseline and pipeline investments differ only in their maturity at the point we submitted our T3 Business Plan in December 2024. Consistency should therefore be established and LOs should not apply to all pipeline investments going through the Load re-opener.

Ofgem needs to remove the application of Licence Obligations to all Load re-opener investments.

Use of Independent Technical Advisor

While Ofgem has not yet provided further details on the proposals for the function and delivery of an Independent Technical Advisor (ITA) in T3, we are supportive of the concept and believe it could accelerate regulatory approval processes and build trust and confidence in the design and delivery of projects.

On this basis, we do not agree with Ofgem's view that the ITA should only be applied to Load Re-opener investments on a limited basis and believe there could be value in application of this resource to complex and high value strategic investments, regardless of driver.

Ofgem needs to provide additional details on the scope and application of the Independent Technical Advisor and be open to expanding the scope to include Load re-opener projects wherever it may add value in streamlining regulatory process time and navigating complex issues.

Project Assessment

We require Ofgem to confirm critical functions of the Project Assessment stage of the Load re-opener process which are not explicit within the Draft Determinations. These include the principle that (1) total project costs are requested, netting off any Pre-Construction Funding allowances agreed to date (2) determinations provided by Ofgem on previous Needs Case and Options Assessment submissions (including technology choice), are not revisited or reverted. Further details related to our position on PCF is included in our response to ETQ26.

TOs must be able to rely on formal decisions issued by the regulator. This principle ensures that continued project development and spend, based on a formal determination, is not undermined through the application of hindsight.

In T2 there have been occasions where decisions made at the Needs Case submission stage were subsequently revisited during the Project Assessment phase, as exemplified by the ongoing Electricity Transmission Control Centre (ETCC) project. In this situation, we have continued significant investment in the project to meet required timelines, which has increased our risk exposure due to Ofgem's revised stance. As we prepare for the substantial investments necessary to achieve CP2030, maintaining pace and certainty in project development is vital. Confidence that the Project Assessment process within the Load re-opener will uphold all applicable prior formal decisions is a fundamental principle we aim to reinforce as part of the reopener.

Ofgem needs to:

- **Confirm that the Project Assessment submission within the Load re-opener will not revisit decisions on scope and technology choice, with the efficiency of the selected option being assessed without considering wider factors**
- **Confirm that the Project Assessment submission includes provision to cover all spend incurred to develop a project to that point less any pre-agreed allowances for PCF.**

ETQ30. Is it clear how the different Load Re-opener tracks operate, and do you agree with the rationale for introducing them?

We agree with the rationale for introducing the tracks in the Load Re-opener, to accelerate delivery and reduce regulatory uncertainty. However we do not support the proposal because a better way to achieve the desired objective would be to adopt our proposals for the joint-management of a submissions pipeline between Ofgem and each TO and in the introduction of guaranteed decision making timetables, subject to protections for the quality of submissions.

If Ofgem retains tracks in the Load Re-opener, we do not agree with the scope of each of the tracks proposed and how they would operate. Specifically, we do not agree with:

- Ofgem's proposal that EJP investment papers submitted in our RIIO-T3 business plan submission, that only presented a needs case and no optioneering information, should move to Track 3.
- The limited scope of eligibility criteria for projects to use Track 2.

In our assessment of these aspects, we have also included our views related to the point in a project's development process in which we can submit Needs Case & Options assessment submission.

Needs Case only Engineering Justification Papers (EJPs)

We do not agree with Ofgem's position that EJP papers submitted in our RIIO-T3 business plan in December which sought needs case only approval should transition to Track 3 (business as usual track) – and therefore be subject to the same review timescales and submission criteria as projects which are still sat within our pipeline and not yet assessed by Ofgem. This would create delay for our investments with the consequential impacts on realising the associated consumer benefits.

While we acknowledge that Ofgem must undertake a comprehensive optioneering and engineering review for these projects, we are concerned that the decision not to enable an agile approach for submission and review of optioneering information outside of Track 3, undermines the value of having proactively shared these investments in December for the purposes of driving pace and slows down regulatory assessment from the outset of the price control.

Ofgem should assign these projects to a Track 1 where we submit a streamlined Options Assessment document that includes only new optioneering information not available during our business plan submission.

Given Ofgem would already have oversight of the need for the investment we propose this should be possible to submit to Ofgem at any time with a minimum notice period of one month. Consistent with ETQ29 proposals, we suggest Ofgem could issue a determination within two months of receiving this submission.

Using PASE as the eligibility criteria for Track 2

We do not agree with the proposed restriction of eligibility for Track 2 (the streamlined track) solely to projects under £200m that adhere to the Electricity Transmission Design Principles (ETDP) and meet the criteria outlined in the proposed PASE framework. There will be examples where in the interests of accelerating delivery that projects do not comply with the ETDP or PASE, for example to support the connection of renewable generation customers given the Government's Clean Power 2030 objective.

Ofgem should ensure the eligibility criteria for Track 2 is broader than engineering factors to reflect the range of drivers for accelerated assessments.

This is in line with Ofgem's impact assessment where it identified a benefit in moving at pace through the uncertainty mechanism framework: *"This will involve lighter touch and earlier assessments of many projects than we would have applied previously. This brings risk that some sub-optimal lower value schemes progress (e.g. where we may have otherwise disagreed with routing or detailed design), however we consider this is necessary to ensure that our decision-making does not impede the delivery of CP2030."*⁷

While we support initiatives designed to streamline regulatory processes, we do not fully support the PASE framework, which has not yet undergone consultation—further details on our concerns regarding the proposal for PASE are

⁷ Ofgem RIIO-3 DD, Impact Assessment, paragraphs 3.13

provided in our response to ETQ69.

Using Accelerator Service (CAS) as the eligibility criteria for Track 2

Ofgem should broaden the eligibility criteria for Track 2 under section 4.67 of the ET Annex, providing investments with a clear Government mandate regarding necessity and delivery timelines, the option to a streamlined regulatory process. At minimum this expansion should include the option for projects identified through the recently announced Connection Accelerator Service (CAS) in the government's June 2025 Industrial Strategy.

Shortening regulatory timeframes and improving the connections process are key objectives in the UK Government's recent Industrial Strategy, which also set out the creation of the CAS. The CAS aims to facilitate more rapid grid connections for demand projects, prioritising those that generate high-quality employment and maximise economic value for the UK. Whilst acknowledging Ofgem needs to protect consumers in any case of expediting regulatory assessment, we consider it feasible to expand the eligibility criteria for Track 2 while upholding robust consumer safeguards.

During RIIO-T2 we have seen a significant rise in the number of strategic demand projects seeking advanced connections endorsed by the Government. These include connections for investments in steel manufacturing, automotive and data centre industries. However, under the T2 regime such projects have still undergone lengthy regulatory assessments through the LOTI reopener, and to date several strategic demand connections have and continue to wait over 10 months to obtain a Needs Case and Options Assessment determination. We are concerned that without access to a streamlined re-opener process where required, delays in regulatory process may impact the timely delivery of critically important strategic investment

We recognise the demand placed on TOs to deliver similar strategically important demand projects is only set to increase. [REDACTED]

Submission of Needs Case & Options Assessment

Ofgem must allow TOs to submit their Needs Case & Options Assessment documentation for regulatory review at Stage 2 design maturity (as per the Design Stage Definitions in the RIGS) - an earlier stage of project maturity than currently proposed by Ofgem which is Stage 3 and before submission of a Planning Application. This will allow the regulatory framework to "dock" into the project development timeline

Stage 2 maturity still provides an appropriate level of engineering design information and optioneering background to enable Ofgem to conduct a comprehensive engineering assessment in the interest of protecting consumers. The benefits of enabling TOs to submit at this earlier stage of maturity would be significant:

- (1) reducing the level of framework risk on investments which would otherwise need to continue to develop and progress without any regulatory certainty;
- (2) therefore speeding up the overall regulatory process at a time when pace is critical to the delivery of CP2030;
- (3) increasing the opportunity TOs have to amend and improve elements of an investment design in the interest of consumers before a point at which it would be difficult to make changes.

ETQ31. Do you agree with the scope and materiality threshold for the Load UIOLI?

We do not agree with the scope and materiality threshold for the Load UIOLI. Our analysis supports an increase in the threshold to £50m and increase in the size of the pot. Ofgem should also make changes to the scope to make it more streamlined and effective at enabling Transmission Owners to deliver at pace. We also do not agree with Ofgem's position that indirects are not included in the scope of funding or Load UIOLI investments and this should be included, as detailed in our response to ETQ58.

Increasing the Materiality Threshold to £50m

Ofgem has not provided evidence to support the proposed £25m threshold for the Load re-opener. Based on an analysis of historic project costs, we consider that £50m is a more suitable Materiality Threshold in T3, given the nature and size of the average project, to allow a larger number of projects to be funded automatically, without the need for a full timely and resource intensive, Load Re-opener process.

We have conducted internal analysis on the distribution of project costs for investments worth less than £100m and how these differ between T2 and our forecast view for T3 and T4. This assessment has highlighted that:

- In T2 c.50% of projects under the cost of £100m were valued at c.£25m or below.
- Based on forecasts for T3 and T4, c.50% of all projects under the cost of £100m are valued at c.£50m or below.

According to these forecasts, if a £25m Materiality Threshold is applied in T3, only 30% of projects valued under £100m would be included in the UIOLI mechanism. This would be approximately a 20% decrease in the proportion of eligible projects compared to a similar scenario in T2.

Provision to increase the size of the UIOLI pot

We do not agree with establishing a fixed Load UIOLI pot throughout the T3 period, without mechanisms or opportunities to adjust its size. It creates the risk that a mechanisms which works effectively at enabling Transmission Owners to progress projects at pace and securing the associated benefits for consumers ceases to function. This would create detriment to consumers as a result of slowing delivery. It would also have additional regulatory burdens on Ofgem and Transmission Owners.

Ofgem must ensure there is flexibility in the mechanism for the UIOLI pot to evolve to respond to unforeseen changes during the RIIO-T3 period. An annual re-opener could be used to evaluate the pot and make any necessary changes.

We recognise the need to protect consumers given the combined value of these projects could be large, even if projects are small on an individual basis. We agree that any unused funds from the UIOLI pot at the end of the period should be returned to consumers. This is an important mitigation, protecting consumers against the risk that the pot estimate is set too high.

Provision to increase the scope of categories eligible for the UIOLI pot

We do not agree with the list of categories deemed eligible for the Load UIOLI. The list should be (1) broadened to encompass additional categories identified (as listed below) as lacking an appropriate pathway to funding and (2) remain adaptable throughout the duration of the price control period, ensuring that other projects—regardless of their underlying drivers—are afforded suitable access to funding should unforeseen needs arise

- **Volume Driver Anticipatory Investment:** Anticipatory investment for Volume Driver projects should be included in the scope of Load UIOLI funding. This is an inconsistency given anticipatory investment can be recovered through a Load re-opener project, but not via a Volume Driver eligible investment. It is in consumer's interest for TOs to undertake small scale anticipatory investment alongside other investments where it futureproofs or enables efficient future delivery e.g. providing civils for a future, albeit uncertain, customer when providing delivering another customer connection.
- **Site Separation** – The pot does not provide funding for costs required to separate shared site services (e.g. water, power) with power stations anticipated to close.
- **Circuit Breaker Replacements** – The pot does not provide funding for costs to fund replacement of Circuit Breakers needed to accommodate increased embedded generation.
- **Reactive Compensation & other operability works** - (such as shunt reactors) can be identified by either NESO or TOs. NESO triggered works are already included under the "Pathfinder" category in the Load UIOLI scope. However, we expect further NGET triggered works driven from future system studies in addition to those included in the T3 baseline. Typically, such investments are below £25m and do not trigger a regulatory output so would not

receive funding elsewhere.

- **OHL reconductoring investments** - If agreement on establishing an OHL Volume Driver is not reached for T3, OHL reconductoring would require funding via the Load UIOLI where projects value falls below the Materiality Threshold value.
- **Hotwiring** – Hotwiring is a low materiality investment designed to give a small increase in the capacity of OHL circuits while utilising the existing conductors. The pot does not provide funding for such costs.

Confirmation of a Single Fund

Ofgem should confirm whether the UIOLI mechanism constitutes a single fund that can be applied flexibly across eligible categories and investments during the T3 period at the discretion of TOs. We have assumed that UIOLI operates as a single fund; however, if this assumption is incorrect, we would have further concerns about the mechanism's effectiveness which we would seek to discuss with Ofgem following submission of this consultation response.

Before Final Determinations, Ofgem should:

- **Increase the Materiality Threshold for the UIOLI pot to £50m.**
- **Provide provide flexibility to amend the size of the UIOLI pot during the price control period.**
- **Include additional categories in the scope of eligibility for the UIOLI mechanism, including; Anticipatory Investment for Volume Driver funding, Site Separation, Circuit Breaker Replacements, Reactive Compensation & Operability investments, OHL reconductoring projects (if these are not covered by a Volume Driver), Hotwiring projects.**
- **Include provision to expand the list of eligible categories for the UIOLI mechanism during the price control, where TOs can demonstrate an investment category does not have means for funding via other areas of the price control and sits within the Materiality Threshold.**
- **Ofgem should confirm whether the UIOLI pot will be applied on the basis of a single fund**
- **Furthermore, Ofgem should ensure Indirects are funded under the Load UIOLI, as per our position in ETQ58.**

ETQ32. Do you agree with our proposed design of the generation and demand connections volume driver mechanisms?

We do not agree with the proposed design of the generation and demand connection volume driver mechanisms other than the selection of cost drivers (i.e. MW, MVA, km). There are a series of methodological errors and issues which we explain in this answer.

We welcome the active engagement with Ofgem on this topic and there are already areas where we understand Ofgem is considering some changes based on our feedback on the proposals set out in the Draft Determination.

By Final Determination Ofgem must:

- amend its approach to include a non-zero intercept within the RIIO-T3 volume drivers;
- consider the use of multi-variable regression when the issues in the data mapping identified in our response to NGETQ7 are resolved and the final regression data set established;
- use additional forward-looking datapoints in its regression analysis to set volume drivers. This means that additional datapoints from other sources (e.g. projects in the pipeline log, RRP25, or investments with non-connection drivers) may be required to enable sufficient sample sizes;
- must extend the use of volume drivers where a strong correlation between cost and outputs can be evidenced, including introducing a OHL volume driver (with an appropriately set atypical threshold) to fund such projects regardless of driver; and
- provide funding within the volume drivers to provide for anticipatory investment that builds capacity and extendibility in the network in investments funded through these mechanisms.

Selection of cost drivers

Based on our own analysis and the experience of RIIO-T2, we agree that there is a reasonable correlation between project cost and the chosen outputs and that connections volume drivers can be calibrated to include sole-use and infrastructure costs.

Treatment of fixed costs via the use of an intercept

We agree that if no output is delivered then the funding from the volume driver should be zero. Whilst there are instances where TOs are required to deliver connection investments that do not deliver a MW output (e.g. to prevent fault level issues, or certain connections linked to NESO pathfinders), we expect these investments to be funded outside of the volume drivers (e.g. via the Load UIOLI allowance or Load Related Reopener).

Every connection project has activities that are not driven directly by the size of the customer project connecting (e.g. project set-up costs). Whilst some of these may vary from project to project, some remain largely fixed. The cost structure of our investments, including these fixed costs, has not changed between projects delivered in RIIO-T2 and those we expect to deliver in RIIO-T3.

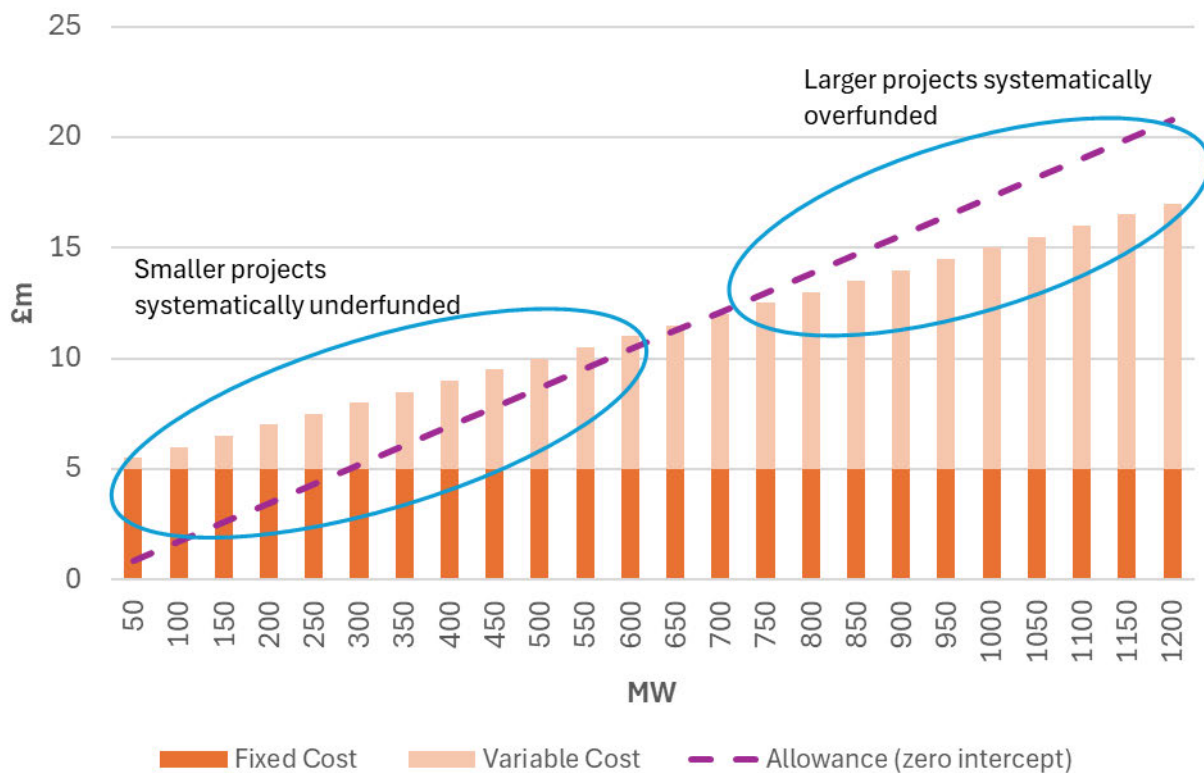
In paragraph 4.100 of the ET Annex, Ofgem states: *“The intercept in a regression model represents the expected value of the total cost when the volume of work is zero, which in RIIO-ET2 represented the fixed cost element. In RIIO-ET3, the data itself reflects the fixed costs, and we consider that the model doesn't need an intercept to account for them. By excluding the intercept, the model does not add any fixed cost twice, avoiding double funding”.* **This is an error - the purpose of the intercept is exactly because the data (i.e. the dependent variable) includes project fixed costs.**

By suppressing the intercept, the regression forces the variable cost driver i.e. MW or km associated with a project (the independent variable) to determine all of the variation in observed total costs (the dependent variable). This leads to poorer model performance and an erroneous unclear directional bias on the unit cost (this will depend on the distribution of the data in each case).

Forcing a regression through the intercept means smaller connections will be systematically underfunded, and larger connections will be overfunded because the fixed costs have not been properly recognised. The following diagram shows how this effect can occur. The example dataset assumes 20 projects sized in 50MW increments,

assuming fixed costs of £5m per connection, and variable costs of £10/kW per project. Undertaking a regression analysis on this data set, fixing the intercept at zero, provides allowances of £17/kW. The highlighted areas show how this results in systematic funding errors. These errors would not arise if an intercept was used.

Figure 1: Impact of setting the regression intercept at zero on investments with fixed cost elements



Ultimately, it should be the regression data that should determine the presence and size of an intercept. The output of the regression analysis (specifically the magnitude of the associated p-values) will provide sufficient information to determine whether or not an intercept is statistically significant. Our own modelling of the connections data shows that it is significant and should be included.

Ofgem must amend its approach to include a non-zero intercept within the RIIO-T3 volume drivers.

Multiple vs Single Factor Regression

Whilst we understand Ofgem's desire to avoid using more complex multi-variable regression analysis, we do not think that this should be immediately dismissed from consideration. The effectiveness of single factor regression is dependent on how well investment costs can be mapped to the identified cost drivers. We recognise this is work in progress and that progress is being made in the area. However, there will be some investments where the costs are not perfectly mappable to each cost driver and the significance of this needs to be understood to see if an alternative approach is justified. We believe that alternative modelling approaches could be justified and should therefore not be ruled out by Ofgem at this stage.

Ofgem should consider alternative modelling approaches when the issues in the data mapping identified in our response to NGETQ7 are resolved and the final regression dataset established.

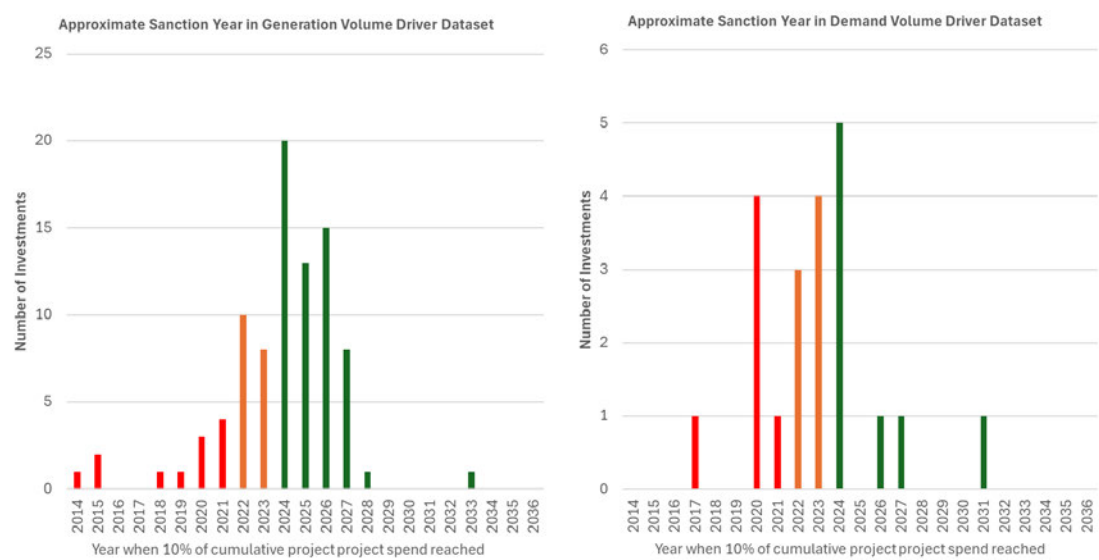
Use of Historical Data

We understand the need to have sufficient observations to ensure the regression provides a statistically significant result. To ensure the sample size is sufficient, Ofgem has made extensive use of historical cost information from RIIO-T2. We consider the data set used is overly weighted to historic data which is not representative of future costs, with the result that the unit costs will not represent the efficient costs.

We have reached this conclusion having conducted the analysis described below. The costs reported in the BPDT have a mix of sources depending on the maturity of the project. Costs reported for completed investments are the actual costs incurred, costs for in-flight investments will be based upon tendered costs, and those in earlier stages of development will be forecast based upon benchmarked costs from our cost book.

The following charts show the number of generation and demand investments fall into the year where cumulative spend reaches 10% of the total project cost. We have used this as a proxy when the market price would have been discovered and fixed through a tender exercise to identify where the costs presented in the BPDT are based on historic market conditions, i.e. to identify to which year the benchmark relates.

Figure 2: Expected timing of tender and sanction of projects presented within the Cost and Volumes table of the BPDT



The red and orange bars show the proportion of projects with historic sanction dates based on our analysis, showing 34% of generation investments, and 62% of demand investments in the Costs and Volumes BPDT have costs based on historical data.

Due to the current supply chain constraints, we have observed significant above-inflation (CPI) increases in the cost of delivering network investments. To quantify this, we have compared the cost of projects in the RIIO-T3 Cost and Volumes tables using the cost-book for our RIIO-T2 submission and the cost-book used in our RIIO-T3 submission. The following table shows how costs have increased beyond inflation for generation and demand investments over the 5 years between the production of the cost books:

Category	OHL	Cable	Substation Costs	Total
Generation	■	■	■	■
Demand	■	■	■	■

We note that a similar analysis could also be undertaken using Ofgem’s PAM models for RIIO-T2 and RIIO-T3 but note that these may also be diluted by the inclusion of historical costs in the respective cost benchmarking (i.e. where costs from RIIO-T1 are included in the RIIO-T2 benchmarking and costs from RIIO-T2 are included in the RIIO-T3 benchmarking).

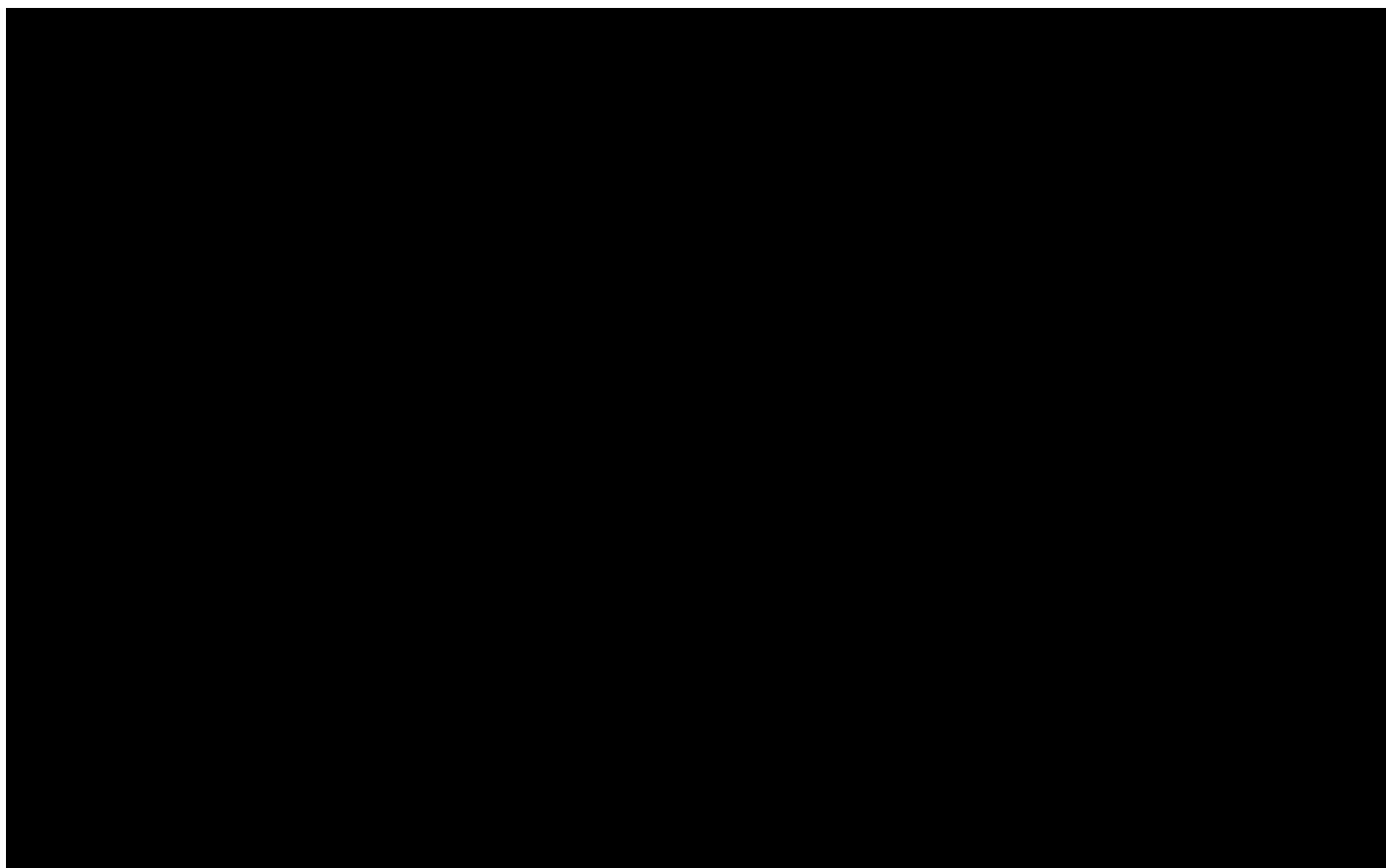
Given the notable cost increases observed, the inclusion of large number of projects with historic costs within the regression analysis will erroneously result in volume drivers that will materially underestimate project costs in RIIO-T3. While some of these future projects might, as a result, be treated as atypical and therefore funded through alternative mechanisms, where this is not the case, volume drivers are likely to systematically underfund projects. This must be addressed.

To overcome this issue, the regression modelling must be undertaken with either only forward-looking datapoints; or including historic costs that have been re-baselined to reflect updated costs.

Ofgem must use additional forward-looking datapoints in its regression analysis to set volume drivers. This means that additional datapoints from other sources (e.g. projects in the pipeline log, RRP25, or investments with non-connection drivers) may be required to enable sufficient sample sizes.

Extension of Volume Drivers to other investment types

As a potential solution, we note that another way to increase the number of observations used in the regression analysis is to use investments with similar scope other than generation or demand connections. This is particularly relevant to the reconductoring of overhead lines, where the majority of projects in our plan are wider network reinforcements where there is a very similar relationship between cost and circuit length, as shown in the following chart:



We understand that Ofgem included wider works projects in its analysis to test the results of the regression analysis undertaken prior to Draft Determinations. We believe that there is a strong similarity between the cost of reconductoring overhead lines regardless of whether the driver is wider network reinforcement, non-load asset replacement, or customers connections. This is because the underlying scope and investment cost drivers are the same. We believe this similarity means these data points can be used to set the overhead lines element of the connections volume driver.

However, we are also of the view that if this data is used to set allowances for connections overhead lines investments, then there is merit in extending the volume driver to fund other types of investment. We believe this provides an opportunity to streamline parts of wider the T3 funding framework, for example, to fund tCSNP reconductoring projects.

We note that in the Sector Specific Methodology Decision, Ofgem removed the wider works volume driver from the list of mechanisms being considered for RIIO-T3. In RIIO-T1 and T2, overhead line wider works projects were funded as part of a 'universal' wider works volume driver and no arrangements were in place for atypical projects. As these volume drivers covered a much wider range of potential investment options (including provision of assets in substations) with a wide range of costs, this resulted in large variations between cost and allowance.

However, by limiting an overhead line volume driver to a specific type of investment i.e. reconductoring, and applying arrangements to dealing with atypical schemes, the perceived shortcomings of T1 and T2 would be avoided.. This approach would reduce the need to assess project-specific costs where the volume driver is sufficiently accurate.

Ofgem must extend the use of volume drivers where a strong correlation between cost and outputs can be evidenced. Specifically, we believe that for overhead line works there is sufficient evidence and data to provide confidence that there is a strong correlation between cost and output, and an OHL volume driver (with an appropriately set atypical threshold) should be used to fund such projects regardless of driver.

Funding of anticipatory investment

Ofgem's Draft Determination provides strong support for strategic investment and providing optionality in designs of projects. Paragraph 5.170 of the ET Annex notes *"in many areas of the UK, we are gradually exhausting the additional optionality constructed between the 1960s and 1980s. As such, we are keen to ensure TOs build future optionality in their designs, where it is economic and efficient to do so"*. Feedback from Ofgem on EJPs which would be considered through reopener processes is clear that optionality should be included in designs. However, the proposals for investments funded through volume drivers there is no funding provision based on the Draft Determination, This is an illogical position which would cause detriment to consumers and would not be in line with Ofgem's stated ambition.

Given the pipeline of future connections and the increased number of connections per site, while undertaking the work to connect one customer it may be efficient to deliver some or all the works at a site in preparation of future customers at the same site. However, this anticipatory investment may not lead to an additional output in RIIO-T3. For example, we may only undertake civils works to prepare for the future connection; or we may build a full connection but without certainty over which customer will use it (i.e. its capacity will not be known). This means this work will not be funded unless explicit additional provisions are made within either within the volume drivers or the other RIIO-T3 funding mechanisms.

Ofgem must provide funding within the volume drivers to provide for anticipatory investment that builds capacity and extendibility in the network in investments funded through these mechanisms.

The following table provides our view of how this type of anticipatory investment could be funded in RIIO-T3. This assumes that allowances set under the connections volume drivers are aligned to the completion of the associated transmission works as mentioned in our response to ETQ36.

Connection Type	Customer driver	Date transmission work completes	Date customer expected	Proposed T3 funding route
Full connection	Identified customer(s)	Within RIIO-T3 or RIIO-T3+2	Within RIIO-T3 or RIIO-T3+2	Volume Driver triggered on completion of works
Full connection	Identified customer(s)	Within RIIO-T3 or RIIO-T3+2	Beyond RIIO-T3+2	
Full connection	Multiple potential customers but specific customer(s) unknown	Within RIIO-T3 or RIIO-T3+2	Beyond RIIO-T3+2	UIOLI / Load Related opener, depending on investment cost. Mechanism required to avoid double-funding in future price control.
Partial connection	Identified customer(s)	Within RIIO-T3 or RIIO-T3+2	Beyond RIIO-T3+2	
Partial connection	Multiple potential customers but specific customer(s) unknown	Within RIIO-T3 or RIIO-T3+2	Beyond RIIO-T3+2	

ETQ33. Do you agree with our proposal to apply the 'stepped TIM' to volume drivers as part of general Totex?

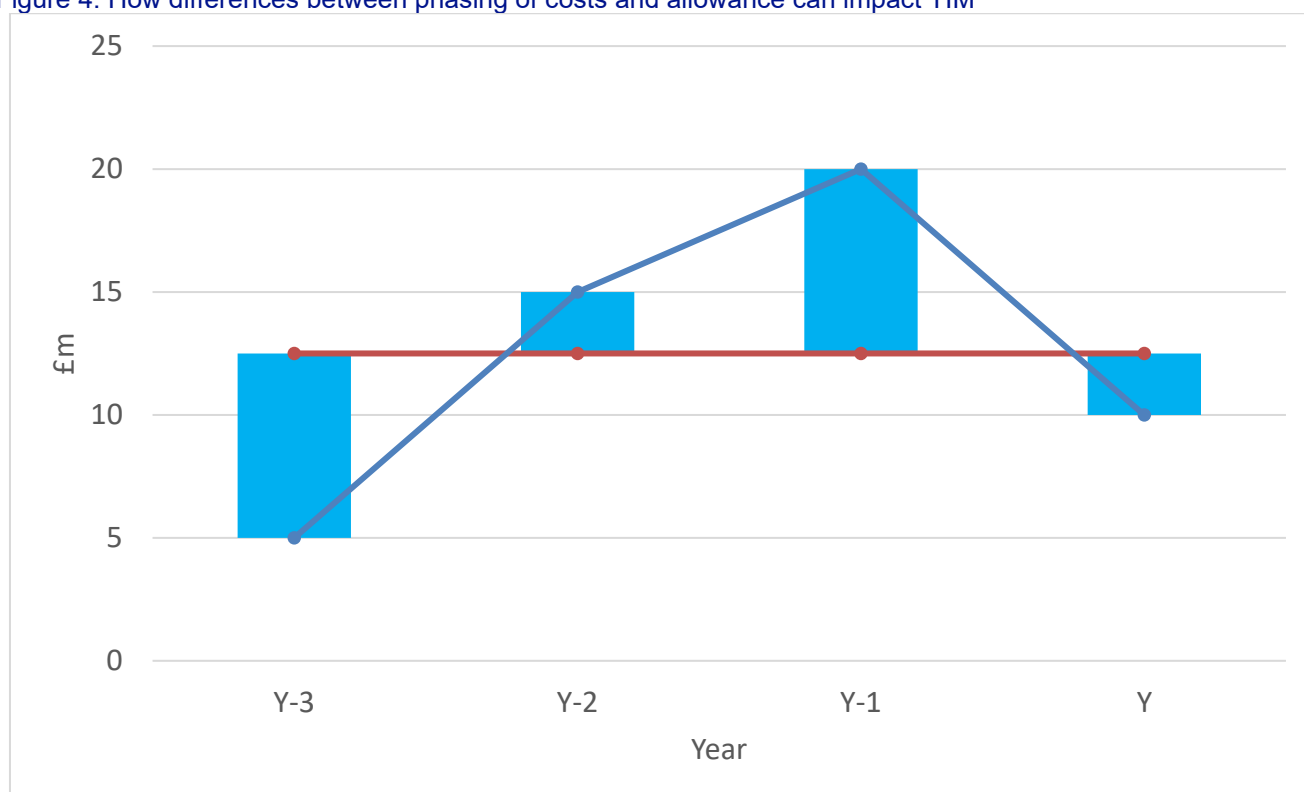
We agree that including volume drivers in general Totex, which is subject to a TIM mechanism, provides incentives on networks to deliver services efficiently, benefitting both consumers and network companies. However, Ofgem's proposal to use a flat four-year profile for allowances is incompatible with a 'stepped TIM' particularly as there is a modelling error in the regression used to determine volume drivers; see our response to ETQ32.

In both RIIO-T1 and T2, the Totex incentive considered the total cost of the scheme compared to the total allowance, and the incentive outcome was independent of the phasing of either factor. However, the proposal in RIIO-T3 could result in gains or losses simply through the application of a stepped TIM coupled with a phasing of allowances that bears no resemblance to actual project expenditure.

The proposal to apply stepped TIM on an annual basis exacerbates this misalignment, with the potential for different sharing rates to be applied across the life of a project depending on the overall position of the portfolio through the years of delivery.

The following chart shows how differences in phasing can impact TIM even when overall cost and spend are equal. In this example, investment of £50m occurs over the four years to deliver an output in year Y with a varying amount spent in each year. Allowances have been phased at a flat 25% per year, consistent with the Draft Determinations. In each year, the difference between cost and allowance is subject to TIM.

Figure 4: How differences between phasing of costs and allowance can impact TIM



Year	Y-3	Y-2	Y-1	Y	Total
Allowance less cost (£m) (a)	7.5	-2.5	-7.5	2.5	0
Assumed Sharing factor (b)	5%	25%	25%	5%	n/a
TIM (£m) (a x b)	0.375	-0.625	-1.875	0.125	-2.0

If a consistent TIM rate is applied across the years in the price control, the phasing difference would net to zero across the period. However, if varying rates are applied as proposed by the stepped TIM set out in draft determinations, then a project such as this with no overall difference between cost and allowance would end up with a non-zero impact from TIM.

For example, if a 5% sharing factor occurred in years Y-3 and Y, but 25% in years Y-2 and Y-1, the overall impact

would be -£2m (as shown in the table above). Consequently, we believe that the introduction of a stepped TIM without appropriate profiling of volume driver allowances will weaken the intended signal of TIM and will result in perverse outcomes exposing consumers to windfall gains and losses arising from unintended consequences from the framework design.

This effect would also come about if Ofgem implements a different approach to TIM for future price control periods. Ofgem should consider the practicalities of how this would work for projects funded via the ET3+2 mechanism proposed in the DD.

An alternative approach which would provide some protection to the TOs for events that are outside their control would be to define “atypical schemes (i.e. where the cost is materially different from the allowance) and adopt an alternative funding mechanism in these instances rather than using a stepped TIM approach to limit consumer exposure. However, we believe this would add more complexity to the regulatory framework.

By final determination Ofgem must:

- **retain the status quo on phasing of allowances for volume drivers or investigate project-specific phasing, aligned to the annual spend profile across the timeframe for which the volume driver is applicable**
- **apply TIM on an annual basis with a true-up at the end of the price control period**
- **consider the offset between price control periods for volume driven projects (T3+2)**

ETQ34. Do you agree with our proposed methodology for excluding atypical connection projects from the regression model?

We do not agree with the proposed approach to excluding connection projects from the regression model as it would remove a significant number of valid datapoints from the dataset used.

Ofgem uses the term 'atypical' to describe two different things: data outliers - projects which should be excluded from the regression modelling (the inputs); and projects where modelling inaccuracies mean costs and allowances are mismatched and judged to be 'atypical' (the outputs).

These are different but appear to be used interchangeably in the Draft Determinations. We have answered this question on the basis that the term refers to data outliers in the inputs and provided our views on the treatment of atypical projects in the outputs in our response to ETQ35.

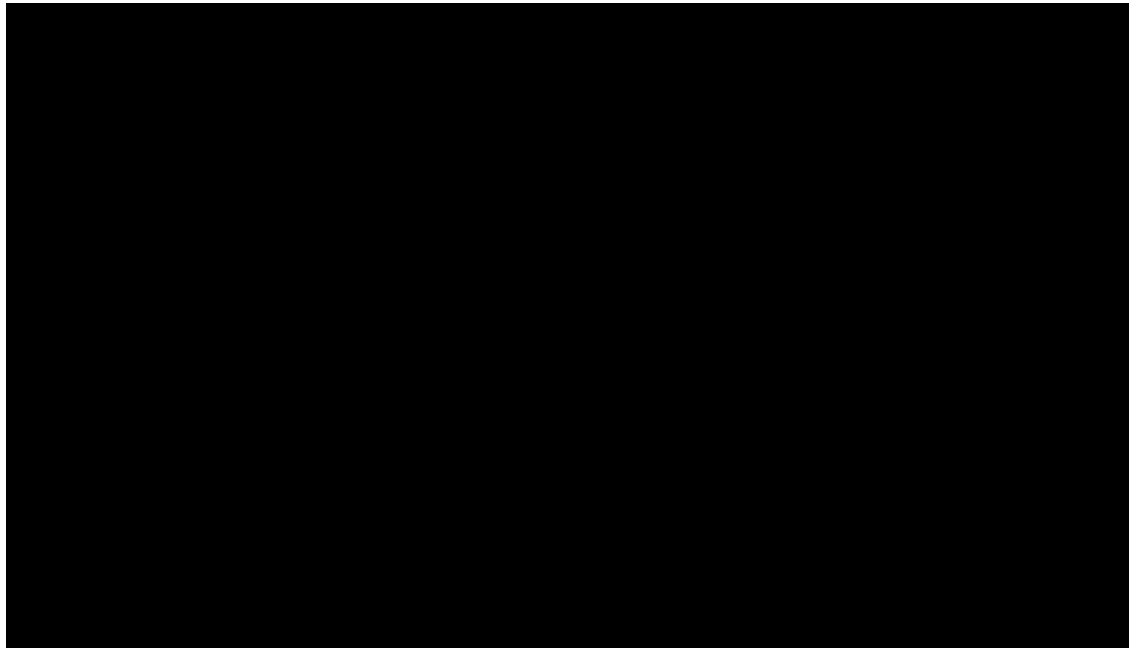
In statistics, outliers are usually identified in normally distributed data using the two-sigma or three-sigma rules, removing data points that are two or three standard deviations from the mean. This equates to removing up to 5% of datapoints.

As such, we believe observations should be removed from the regression analysis as outliers only in exceptional circumstances where their inclusion would distort the results of the regression. In all other cases, genuine observations of projects with high or low unit costs – regardless of whether that is driven by cost or volume – should be included in the regression model. If they are not, the modelling results will be distorted, and they will not consider the range of circumstances that could be expected to occur during T3.

Against this background, Ofgem's proposed approach does not follow modelling best practice for regression datasets and removing observations where cost, volume, or unit cost is 1.5 x the interquartile ranges of each is unjustified. It applies a method typically used for data of a single dimension to multidimensional data and, as such, does not consider variation of data points from the relationship between cost and volume in a manner recognised as standard practice.

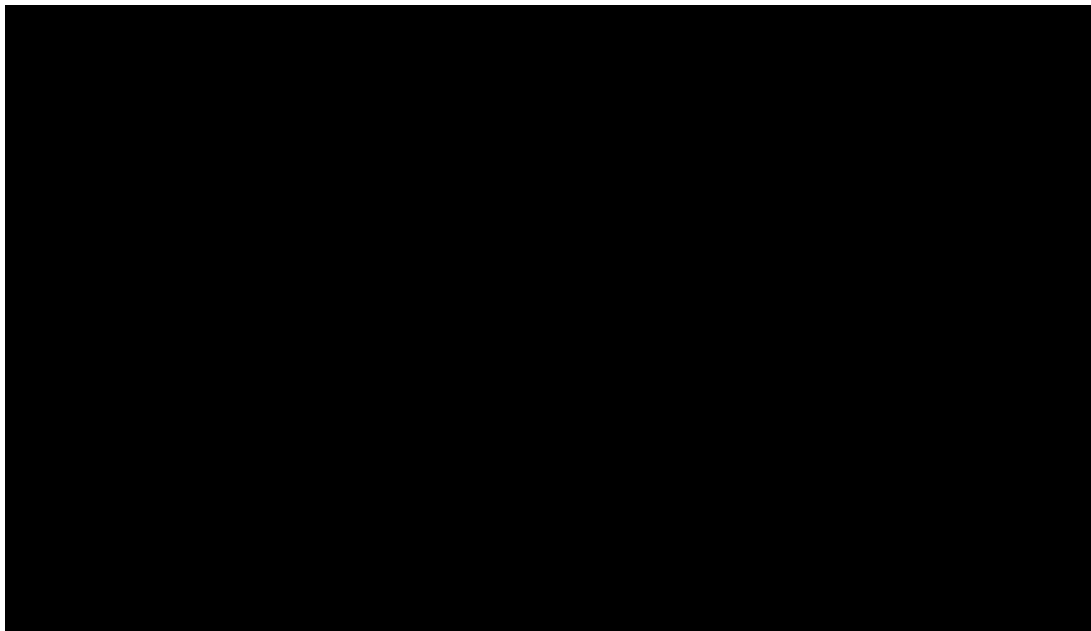
The methodology described in the Draft Determinations would remove a significant number of datapoints from the dataset. For example, using the regression information provided by Ofgem for generation connections, those observations that lay in the grey area in the following chart would be treated as outliers. This result underpins why the approach is not appropriate – statistical models including regression models work best when there is a large sample of data.

Figure 5: [NGET interpretation of Ofgem outlier identification method](#)



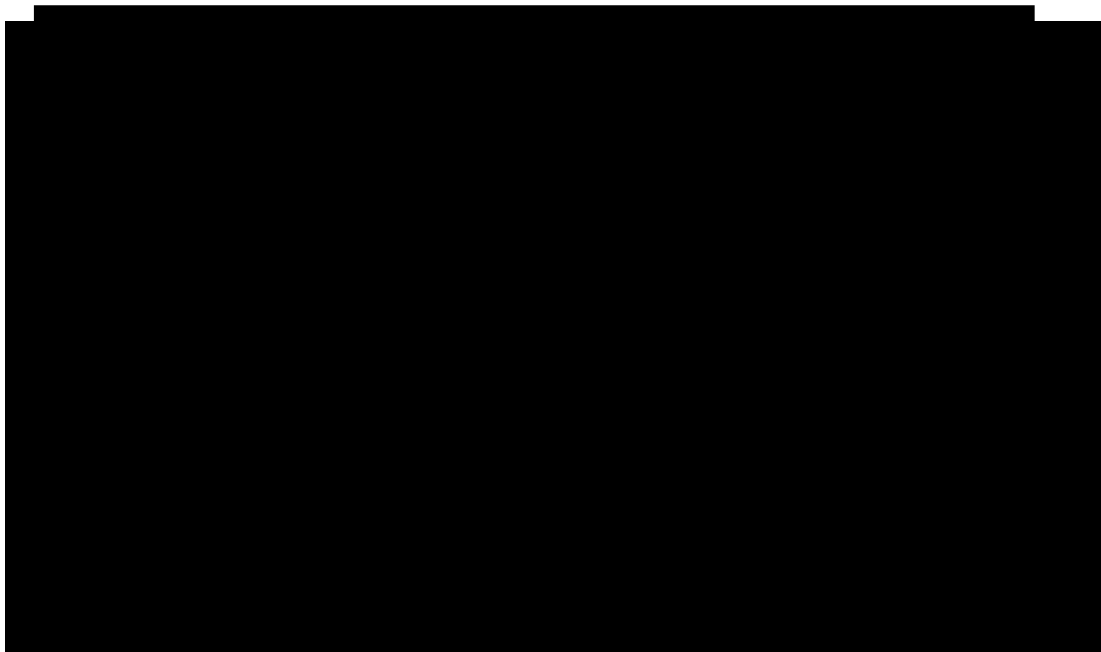
Notwithstanding these concerns, the approach described in Draft Determinations has not been applied to the modelling used in Draft Determination and this results in a different set of observations being removed, as shown in the following chart for Ofgem's generation dataset:

Figure 6: **Outliers identified by Ofgem**



Ofgem should identify an initial set of outliers using the standard error of a regression analysis, removing any points that deviate from the identified trend by more than twice the standard error (the two-sigma rule). In Ofgem's generation dataset, this would remove a much lower number of points than used for draft determinations:

Figure 7: Outliers identified using standard error



The two-sigma rule assumes a normally distributed set of datapoints. This may not necessarily be the case for the volume driver regression datasets, so further inspection may be required. In combination with applying the 2-sigma rule, datapoints should also be reviewed to ensure that the projects they reflect represent a typical scope and cost for connections of their size. Ofgem's method could be used to identify the additional potential outliers to be reviewed in this manner.

By Final determination Ofgem must:

- Review its approach to excluding connection projects from the regression models by adopting the standard error of a regression analysis, removing any points that deviate from the identified trend by more than twice the standard error (the two-sigma rule).
- In combination with applying the two-sigma rule, review datapoints to ensure that the projects they reflect represent a typical scope and cost for connections of their size.

ETQ35. Do you agree with our proposal to use the Load Re-opener (above £25m) and Load UIOLI (below £25m) to fund projects outside +/- 1.5 standard deviations from the regression model?

We agree that the Load Related Reopener (LRR) and Load UIOLI provide alternative funding routes where projects are judged to be 'atypical'. However:

- i) £25m is not the right threshold for UIOLI;
- ii) given issues with the modelling approach and the dataset utilised to date further analysis is required before a conclusion that +/- 1.5 times the standard deviation from the regression model is the most appropriate threshold for determining if a project is atypical; and
- iii) further detail is needed to describe how the atypical thresholds will work in practice given the change in modelling approach (single variable verses multiple variable) and the likelihood that there will be several outputs associated with individual projects.

By Final Determination Ofgem should:

- simplify the number of re-opener mechanisms noting that the regulatory burden is likely to delay projects to the detriment of consumer benefit
- derive the threshold to identify atypical schemes using the standard error of the regression model rather than the standard deviation of a single dimension of the dataset used as an input for the regression
- assess the appropriate sizing of atypical thresholds once issues with the modelling approach and dataset have been resolved and the regression output can be assessed;
- consider varying thresholds by output where large concentrations of projects are likely to pose additional risk to consumers and TOs;
- clarify how the atypical thresholds for different volume drivers will operate in combination for a single project;
- amend the application of UIOLI and LRR to ensure that projects with similar levels of cost deviation from the volume driver are treated consistently, and that all atypical projects with costs that fall below the lower atypical threshold are funded via UIOLI
- continue to share their modelling with TOs

Use of alternative mechanisms and associated trade-offs

We agree that the Load UIOLI mechanism and the LRR both provide suitable alternatives to fund projects that are judged to be 'atypical'. RIIO-T3 needs to prioritise pace of delivery and this needs to be supported by the funding framework. However, there is a trade-off required between the number of resource intensive re-openers (regardless of the track used); the time these each take and the impact on project delivery timescales; and the additional protection this might provide consumers. This is explored in our response to ETQ31 and in our paper on 'A workable uncertainty mechanism framework for RIIO-ET3' provided as part of this submission.

Ofgem should simplify the number of re-opener mechanisms noting that the regulatory burden is likely to delay projects to the detriment of consumer benefit

Atypical threshold derivation

Atypical schemes should be assessed using the standard error of the regression model rather than the standard deviation of a single dimension of the dataset used as an input for the regression. The standard error measures how well the regression model represents the population it seeks to represent. In contrast, the standard deviation measures the spread of an individual dimension of the inputs to the model i.e. the population of observations fed into the regression analysis, rather than the relationship between cost and output.

Ofgem should derive the threshold to identify atypical schemes using the standard error of the regression model rather than the standard deviation of a single dimension of the dataset used as an input for the regression.

It is too early to determine whether 1.5 x the standard error is an appropriate threshold in T3. In T2, 1.5 standard errors represented an error of approximately +/- £15m (in 23/24 prices) and was an arbitrary choice made at the time. Given the issues we have highlighted on the modelling techniques and dataset used to reach the volume drivers included in the Draft Determinations, we believe that the atypical threshold in T3 should only be set once further modelling has been completed and the magnitude of the standard error is known. This will depend on the level of variation between cost and output in the overall data set. Should this variation result in a materially different standard error than that observed in RIIO-T2, then setting the atypical threshold at 1.5 times the standard error would materially change the level of risk borne by TOs and consumers.

Ofgem should assess the appropriate sizing of atypical thresholds once issues with the modelling approach and dataset have been resolved and the regression output can be assessed.

Additionally, the distribution of expected future connections may also need to be considered. We are wary that there is a high volume of smaller (sub-150MW) generation projects in our plan (and projects of this size might be more likely to receive 'Gate 2 offers' in connection reform because smaller projects might secure planning permission more easily). These have a lower range of costs than larger projects. Setting the atypical threshold based standard error for the full dataset may result in the vast majority (if not all) projects of this size being subject to the volume driver regardless of its accuracy for these types of project. We are wary that the large volume of projects of this size that may be over or underfunded by the volume driver, may risk a material over or underspend. As such we believe that there may also be a case to have a smaller threshold for smaller projects where the standard error may be large compared to the project cost. This would need further development to ensure an equitable balance of risk between TOs and consumers.

Ofgem should consider the uses of a smaller threshold for smaller projects where the standard error may be large compared to the project cost.

Ofgem should consider varying thresholds by output where large concentrations of projects are likely to pose additional risk to consumers and TOs.

Application of the atypical thresholds

The application of 'atypical' thresholds needs to be clarified and tested under different scenarios, particularly where there are multiple outputs of different types. It is not clear how many thresholds will apply and how precisely these would be derived / interact. However, we do note that deriving OHL and cable volume drivers via different regression models would naturally lead to separate atypical thresholds (unlike those in RIIO-T2). If this is the case, the risk TOs and consumers face could vary dependent how these interact. For example, if the substation element of a project falls £6m within its atypical threshold, but the OHL element of a project lies £5m beyond the threshold, it is not clear whether the project would be considered atypical (because the OHL threshold is breached) or not (because the net position lies within the total of the thresholds).

Conversely, if the thresholds are aggregated based on the type of outputs delivered, the level of risk faced by TOs and consumers for some projects could be notably different from that faced in RIIO-T2 (e.g. if a project delivers cable, OHL, and MW outputs, then the atypical threshold could be much greater than a project only delivering the substation element).

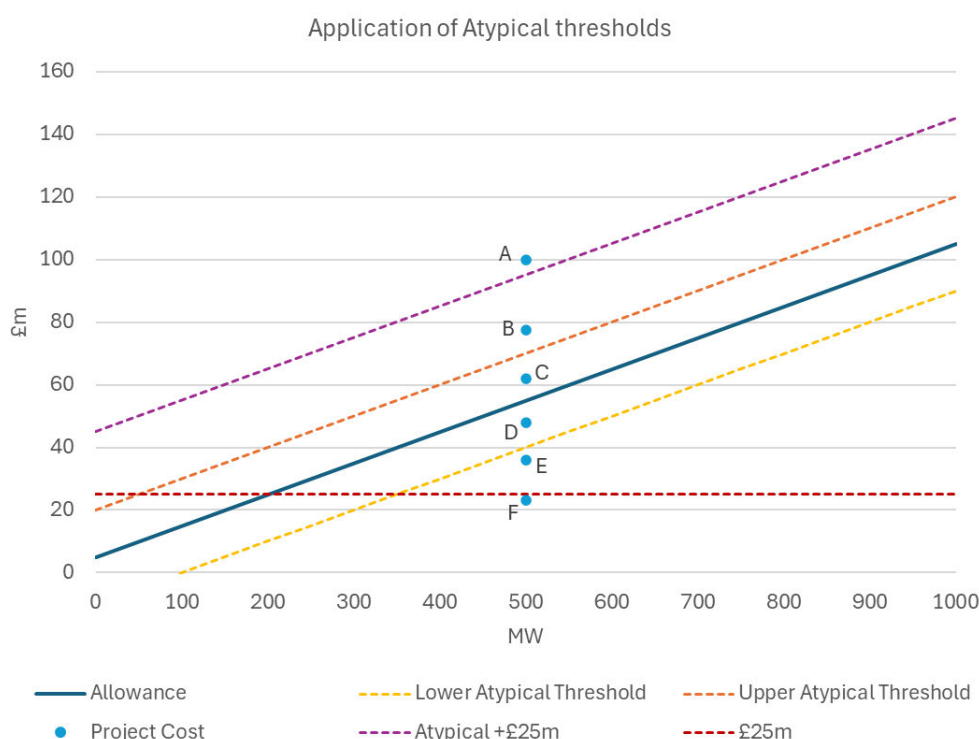
It is not just for projects with multiple outputs where it is unclear how the atypical thresholds will apply. Whilst our understanding is that they should operate in a similar fashion to RIIO-T2, it is not clear this is what is intended from the way in which these have been derived in data shared by Ofgem.

It is our view that for projects with a single output, atypical thresholds should operate in a similar fashion to RIIO-T2. This means that projects A, B, E and F in the diagram below would be considered atypical, whilst projects C and D would be funded via the volume driver. Additionally, our interpretation of the Draft Determinations is that projects A, B, and E would be subject to LRR, whilst project F would be funded via UIOLI.

Assuming our interpretation is correct, the diagram below also highlights two key characteristics of the proposed mechanism:

- i) it is likely that projects will be subject to cost assessment via the LRR because their cost is deemed lower than would typically be expected for the size of output (e.g. project E), which seems counter intuitive; and
- ii) dependent on the gradient of the volume driver equation, and the size of the atypical threshold, there may be limited scope for atypical projects to be funded by UIOLI, especially where cost exceeds volume driver allowance. This could result in projects that are atypical by a similar extent being funded differently. For example, assume the atypical threshold is £10m. A scheme costing £20m with a volume driver allowance of £10m, would be treated as atypical and funded by the UIOLI mechanism. However, a £40m scheme with a volume driver allowance of £30m would also be treated as atypical and funded by LRR. In both cases the error in the volume driver is £10m yet they could follow different funding pathways

potentially adding many months of regulatory process to one. Having break-points like this may also lead to further problems. For instance, a project that we expected to be atypical and funded by UIOLI could have a small cost change during development resulting in the LRR being needed, and only at this point would that be known



We therefore believe that an alternative approach to how atypical projects are funded would be more appropriate. This has two elements:

- i) All projects that fall below the lower atypical threshold (e.g. projects E and F) should be funded via the UIOLI arrangements. Whilst this means that projects above the proposed UIOLI threshold would be funded by this mechanism, this would only apply to projects where the cost is lower than the efficient cost determined by the volume driver and avoid additional months of regulatory process; and
- ii) Where projects fall above the higher atypical threshold (e.g. projects A and B), the alternative funding mechanism should be based on the degree to which the project is atypical rather than the value of the scheme. For example, a project could be UIOLI funded regardless of its value provided it is not more 'atypical' than £25m (e.g. project B); and LRR would be used beyond this i.e. where design choices are likely to be materially different from that assumed by the average in volume driver (e.g. project A).

It should be noted that any change to the atypical thresholds or how anticipatory investments are funded will affect the size of the UIOLI fund needed and likely give rise to needing to be able to adjust this during the price control, given the uncertainties are outside TOs' control.

Ofgem should clarify how the atypical thresholds for different volume drivers will operate in combination for a single project;

Ofgem should amend the application of UIOLI and LRR to ensure that projects with similar levels of cost deviation from the volume driver are treated consistently, and that all atypical projects with costs that fall below the lower atypical threshold are funded via UIOLI

Ofgem should continue to share their modelling with TOs

ETQ36. Do you agree with our treatment of RIIO-ET3 Volume Driver crossover projects and our approach to allowance profiling?

We do not agree with the proposed approach to crossover projects. The proposed approach would leave funding gaps between T3 and T4.

We do not agree with the proposed allowance profiling as it is overly simplistic and does not reflect genuine project spend profiles. The Draft Determinations are also not clear when volume driver allowances will be triggered. We believe that allowances should be triggered when TOs have completed their investment and the annual profiling of allowances made in reference to this.

Funding of crossover projects

Ofgem has recognised the need for price controls (that last 5-years) to avoid becoming a barrier to investment across that cross-over period. However, we do not agree with the proposed solution for crossover projects since the proposed approach will leave funding gaps between T3 and T4.

We believe Ofgem could have considered other options, such as fixing project allowances at the point when investment decisions are made as this approach is understood and already works successfully to bridge some of the gap between T2 and T3. That said, funding gaps will remain (e.g. longer lead time investments delivering beyond the second year of RIIO-T4), and the price control needs to recognise this and set out upfront how these will be treated, for example, better signalling of what will be treated as part of the T3 close-out process.

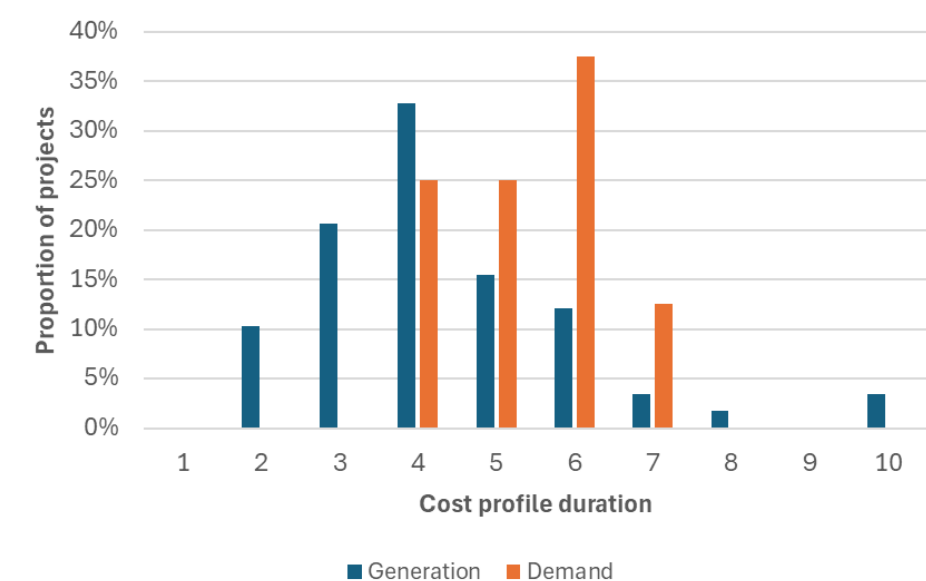
Ofgem must commit to fund all “funding gaps” that arise between the RIIO-T3 and T4 price controls that may arise as a result of the limited nature of the automatic volume driver crossover arrangements.

Profiling of allowances

Ofgem’s proposal to implement flat-phased allowances is a backwards step for RIIO-T3 as the phasing used in RIIO-T1 and T2 seeks to mirror the spend profile of a typical project. This flat profiling also creates specific issues for the proposals in the draft determination with a ‘stepped TIM’ and these are discussed in our response to ETQ33.

In light of the issues linked to stepped TIM, we have considered the manner in which volume driver allowances could be profiled. We have started by considering the duration of demand and generation projects in the BPDT Cost and Volumes table. This counts the number of years where the total project spend is greater than 1% of total project cost for forward looking projects (i.e. those not sanctioned at the time of submission). The following chart provides a view of this analysis:

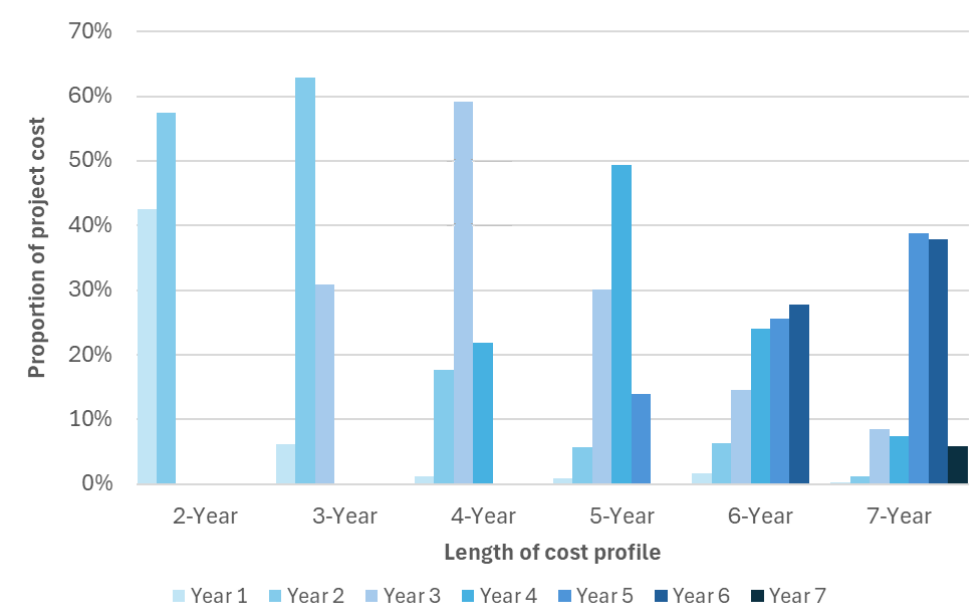
Figure 8: Proportion of projects delivering future connections outputs by project length (years)



There is notable variation in the duration of connection projects, with demand projects typically being longer than generation projects. This is consistent with the need to install additional assets (notably transformers) to connect demand customers. We will note that for generation, the observed variability links to the diverse size and nature of generation projects our customers intend to connect to the network.

We have also used the same dataset to determine typical annual spend profiles for projects of different durations, as shown in the following chart. Each block of bars represents the average annual profile for a project of that duration. For example, an average project lasting 3 years (the second block of bars) has annual profile of 6%, 63%, and then 31% of project spend across its life. These profiles are significantly different from the proposed four-year flat profile of 25% per year included in the Draft Determinations. However, they also show that there is significant year-on-year variation between profiles.

Figure 9: Typical connection cost profiles in the Cost & Volumes table



Ofgem must as a minimum retain the (RIIO-T2) approach on phasing of volume driver allowances. However, we believe Ofgem should review phasing profiles or investigate whether project-specific phasing, aligned to

the annual spend profile across the timeframe the volume driver is applicable and could be used to remove this effect entirely noting the impact on Ofgem's stepped TIM proposals.

Allowance trigger points

The purpose of profiling allowances is to spread expenditure over time to reflect when costs are expected to be incurred. Historically, this has been linked to the timing of a customer connection on the basis that connections have been delivered as needed. However, as the demand for connections and the overall need for network investment has increased, we have needed to take a more strategic approach to investment. This means that connection investment may be undertaken in a more anticipatory manner, with some being delivered before the customers' connection date, maximising opportunities to bundle works and the use of available system access. We have also experienced issues in T2 where TOs have completed their work but the customer has delayed or cannot commission its own assets.

It is also worth noting that even with the project-specific profile, noted above, there is a need for the trigger point for the allowance to be set. For example, if work is delivered in RIIO-T3, but the customer connects in the third year of RIIO-T4, it is appropriate for funding to be set as part of the RIIO-T3 volume driver and aligned to when the cost is incurred.

Ofgem should align the profiling of allowances and spend, the allowances for the RIIO-T3 volume drivers that Ofgem sets should be based upon and profiled with reference to the completion of the associated transmission works, rather than the completion of the customer's connection

ETQ37. Do you agree with the proposed scope of the CSNP-F Re-opener?

We do not agree with the proposed scope of the CSNP-F re-opener. The creation of a separate CSNP-F reopener is not necessary and adds unnecessary complexity and is not in line with Ofgem's objective to streamline the RIIO-T3 framework.

Whilst we agree that there will be differences in how projects arising from NESO's strategic planning processes are treated relative to other projects (e.g. in need confirmation and timely delivery incentives), we do not agree that creating separate reopeners is in keeping with driving a simple and agile framework in RIIO-T3 which facilitates the high volume of investments required to enable CP2030 and Net Zero.

Major load investments are currently split between the proposed Load Re-opener and CSNP-F re-opener in RIIO-T3, based on whether the investment is pending confirmation from NESO's CSNP publication, due in 2027, or other NESO led network plan. However, as described further in our response to ETQ1, there is currently a lack of clarity over the intended scope of the CSNP-F Re-opener. It is possible that the CSNP-F Re-opener could cover the outputs of NESO's tCSNP2 Refresh and CSNP exercises, as well as other projects such those that might otherwise be considered under the Load Re-opener.

Separate re-opener mechanisms differing only between the scope of eligible projects and the design of component parts of the re-opener process, further complicate an already complex RIIO-T3 framework. This is compounded by the fact that the CSNP-F ODI-F delivery incentive may be applied to projects that are not CSNP-F Outputs.

To enhance simplicity within the framework and reduce licence complexity, we propose amending the current model by reforming the Load Re-opener into a general re-opener that is agnostic to the investment driver. This approach would establish a more streamlined and efficient route for re-opener assessments, applicable to projects irrespective of whether they are prompted by load, non-load, or shared driver requirements.

The distinct regulatory features of CSNP projects - such as pre-established need, a delivery incentive (ODI-F), and the use of an Independent Technical Assessor - can be effectively addressed through a general re-opener by having these as options to be included on a case by case basis on the basis of collaborative discussions between Ofgem and TOs during the initial stages of the process, based on what is the best value approach for consumers.

Further information related to this proposal is explained in ETQ29, ETQ38 and ETQ44 of this document, as well as presented within our Workable Framework paper, provided alongside this submission.

If Ofgem did not accept our proposals as set out in the Workable Framework paper in RIIO-T3, there are specific aspects of the design of the CSNP-F re-opener, aligned with the Load re-opener, with which we do not agree. As a minimum these would need to be addressed to ensure the mechanism could deliver in a suitably agile and efficient manner for consumers in T3. These reflect many of the suggestion included regarding the Load Re-opener (within ETQ29 of this response) and also detailed below in ETQ38.

Ofgem should amend the Load Re-opener to become a general re-opener agnostic of investment driver – removing the requirement for a separate CSNP-F re-opener.

ETQ38. Do you have any views on our proposed design of the CSNP-F Re-opener?

We do not agree with the design of the proposed CSNP-F Re-opener. It does not support delivery of a simplified and agile RIIO-T3 Uncertainty Mechanism Framework. Furthermore, there is not enough clarity on key areas of the re-opener to be able to determine whether the re-opener is a workable solution and investable.

Ofgem should simplify the framework through the creation of a general re-opener process agnostic of investment driver, as proposed in the Workable Framework paper provided alongside this response and our response in ETQ37 above.

However, if Ofgem does not adopt our Workable Framework proposal and a CSNP-F re-opener remains in place for the RIIO-T3 period, then the following response summarises the minimum required changes and clarifications needed to enable a workable solution.

We suggest that the design be developed further, or that clarification be provided in line with the areas outlined in ETQ1 as well as the following areas:

Assessment of NESO Output

The process by which NESO's output from the CSNP will be incorporated into the TOs' regulatory framework (CSNP-F) requires further clarification. Specifically, there is a lack of detail regarding how Ofgem intends to assess the quality of this output to ensure it provides an adequate foundation for imposing obligations or requests on TOs.

Ofgem should clarify the process it will use to assess the quality of NESO's CSNP and network led process outputs for adequateness for imposing obligations or requests on TOs.

As discussed further in our response to ETQ2, Ofgem must apply its own scrutiny to the outputs of the CSNP process and commit to consulting with TOs on the dates to be used as targets, rather than simply taking the output of the CSNP process.

Ofgem must apply its own scrutiny to assess and verify the inputs provided by the TOs, rather than relying on NESO analysis. This should be supported by the proposed Independent Technical Adviser.

Submission Windows & Review Timescales

Consistent with our response to ETQ29, we have identified additional elements of the Load re-opener design—also present in the proposed CSNP-F re-opener design, notably the bi-annual submission windows and Ofgem's suggested six-month review period—that raise concerns regarding the flexibility and efficiency of the re-opener process. These design features would cause unnecessary delays in the development and approval of projects, focusing networks to progress projects more slowly, which delays the benefits to consumers of CSNP schemes.

Ofgem must amend the submission windows and review timescales to rolling monthly submissions and 2-month review periods, as per our response in ETQ29.

Cost and Output Adjusting Events (COAE) and Delay Events

As covered in further detail in our response to ETQ4, Ofgem needs to provide further clarity on the way the COAE, Delay Events, and CSNP methodology change control process interface and coordinate with the CSNP-F.

Ofgem needs to include a robust and clearly defined change control process to provide TOs with confidence in the investability of the CSNP-F and ensure the COAE and Delay Events features of the mechanism are workable.

Given the potential scale of works associated with the CSNP-F, the absence of such a process will have wider implications for financeability and investability.

tCSNP2 Interactions

Further clarity is required on how the CSNP-F re-opener will be designed to consider and interact with tCSNP2 driven projects.

Ofgem has explained it is still considering *“whether tCSNP2 and tCSNP2 Refresh projects are best progressed ... using the Load Re-opener or the CSNP-F Re-opener”* and that *“projects with a 'proceed' signal in the tCSNP2 Refresh” might be included in the ODI-F*.

Ofgem needs to provide further clarity in advance of Final Determinations on how tCSNP2 projects will be progressed between the current proposed Load and CSNP-F re-opener processes in RIIO-T3

CSNP-F ODI-F Delivery Incentive

Further details on our position on the proposed CSNP-F ODI is included in our response to ETQ1, ETQ2, ETQ3, ETQ4 and ETQ5.

Licence Obligations

Our position related to the proposal to establish Licence Obligations, as well as the ODI-F is detailed in ETQ5. A summary of our view is that the ODI-F is an adequate incentive for timely delivery and that the addition of LOs is disproportionate. However, if LOs do apply, the current proposal for setting dates is unacceptable. This will lead to open-ended regulatory risk and asymmetry which may make the re-opener and incentive not investable. If LO delivery dates are to apply then these should 1) apply from a point no earlier than that at which the ODI-F penalty cap has been reached, to avoid 'double jeopardy', and 2) be set at the Project Assessment stage, when detailed design has taken place to allow greater TO confidence in the target date.

Ofgem must remove Licence Obligations alongside ODI-F for all CSNP-F investments – or at minimum:

- **Ensure the LO date set is at a point no earlier than the ODI-F penalty cap has been reached**
- **Ensure the LO date is not set before the Project Assessment stage.**

ETQ39. Do you agree with our proposed approach to T2/T3 crossover projects?

We agree with Ofgem's commitment to "ensure that no efficient and justified investment is left unfunded solely due to projects falling between regulatory funding periods". However, we do not agree with the Draft Determination position because it fails to propose an approach for funding the majority of the T2/T3 crossover projects, equating to a material gap of over £5bn in the overall price control framework.

Ofgem's Draft Determinations state that it has excluded such projects when setting the T3 baseline direct capex allowances, and from the metrics used to assess funding for Closely-Associated Indirect and Business Support Costs. Due to the scale and duration of our investments, we have in excess of £5bn of projects where spend has and will occur in both the T2 and T3 periods, i.e. crossover projects. This is split 54%:46% between the T2 and T3 periods respectively.

These are high confidence projects which are already in flight and in which NGET is already making significant investments. Their exclusion leaves a material funding gap in the regulatory framework which significantly impacts their deliverability.

Ofgem must work with TOs and consult appropriately on proposals ahead of Final Determinations to provide clarity on how these crossover projects will be funded. As part of this engagement Ofgem must:

- **Agree all categories of T2/T3 crossover projects that require resolution through a comprehensive T2/T3 crossover solution**
- **Determine an appropriate funding treatment for each category of projects**
- **Identify how corresponding indirect funding will be provided**
- **Identify when funding will be provided**
- **Urgently consult on its proposed position in order to provide clarity prior to Final Determinations.**

Our concerns with Ofgem's Draft Determinations proposed approach for T2/T3 crossover projects

There are five key reasons why we do not agree with the Draft Determination position on T2/T3 crossover.

No commitment to consulting on proposals before Final Determinations

The fact that Draft Determinations have not set out how crossover projects will be funded means that there is a substantial gap in our understanding of the T3 framework. We have requested engagement on this material issue with Ofgem; however, we have not had any Working Groups or substantive bilateral discussions with Ofgem at the time of compiling this response.

Ofgem has indicated that our first opportunity to discuss this issue substantively will be 23 September 2025. There has been no commitment to consulting on proposals prior to Final Determinations, in the absence of which, the first time we will see a formal position from Ofgem will be at Final Determinations.

There will have been no opportunity to comment on Ofgem's proposals, which would be a clear procedural failure and in breach of Ofgem's own consultation policy and public law duties. Ofgem must engage in consultations with TOs on its proposals and conscientiously take the product of that consultation into account ahead of Final Determinations.

The commitments in the Draft Determinations do not cover all funding required

The Draft Determinations refer to:

- (i) providing T2 funding for delayed projects using the T2 close-out process; and,
- (ii) funding T2 costs for T3 projects initiated in T2, through either:
 - the T2 close-out, or
 - the T3 framework.

However, this view is incomplete because it focuses on T2 funding gaps and does not indicate when or how T3 funding will be provided for T2/T3 crossover projects. T3 funding cannot be provided via T2 close-out. T2 close-out can only provide adjustments to allowances where the T2 framework already provides for it, e.g. closing out evaluative PCDs that have completed in the T2 period. Therefore, it is essential that T3 Final Determinations provide clarity regarding the necessary funding framework for T3 costs, and that this is appropriately consulted on prior to T3 Final Determinations.

Draft Determinations do not provide any detail regarding how or when funding will be provided

There is no detail provided regarding how or when T2/T3 crossover funding would be provided. This may require specific provision in the new T3 mechanisms and the T3 licence, as well as changes to the T2 licence and framework in anticipation of those mechanisms.

This detail is necessary to provide regulatory certainty and to allow work to progress with confidence as we move between price controls.

Ofgem's initial view that funding for crossover projects would be addressed via T2 close-out introduces considerable uncertainty because:

- As mentioned above, T2 close-out can only provide adjustments to allowances where the T2 framework already provides for it, e.g. closing out evaluative PCDs that have completed in the T2 period. T2 close-out cannot provide T3 funding for projects in most circumstances.
- Based on the T1 closeout experience, it could be late 2029 before we have an agreed funding position.

This uncertainty would slow down decision-making, delaying the delivery of investments that are required to bring benefits for consumers. Without certainty that allowances can be recovered, the natural response will be for TOs to slow the pace of delivery to minimise crossover projects. Lack of regulatory clarity would cause consumer detriment.

Inconsistency of treatment

Ofgem has not consistently applied the policy position on T2/T3 crossover as set out in the Draft Determination (DD). In the DD, Ofgem explains that it has excluded all T2/T3 crossover projects from its cost assessment process and allowance setting. However, there are £437m of non-load related investments which were not excluded and were assessed via PAM and direct capex funding provided. We are unclear whether that was deliberate or an error.

If deliberate, we will have to review the projects that have been assessed to confirm whether allowances should be provided via this route or not. Furthermore, the indirect costs associated with these same projects have been excluded from assessment, resulting in these projects being approved but underfunded.

An example of the errors potentially introduced by this approach is funding for our SCADA project. SCADA was excluded as a crossover project, but was cost assessed and had funding proposed, before the *deduction* was taken out again – resulting in negative funding. This approach is clearly flawed and Ofgem must correct this error. We have set out our proposed approach to funding SCADA in response to ETQ52.

Lack of clarity regarding funding of Indirect costs

There is no acknowledgement that funding for efficiently incurred and necessary associated closely associated indirect costs must also be provided, or how such funding will be provided.

Ofgem must confirm ahead of Final Determinations that this funding will be provided and how it will be done.

Summary of funding 'categories' requiring funding treatment agreement

To assist Ofgem with developing the T2/T3 crossover framework, we have set out a summary of all the different 'categories' of project funding and made a proposal as to how each category should be funded (both for T2 and T3, direct and indirect costs).

In addition to this summary, we will shortly provide further detailed analysis of T2/T3 crossover projects to illustrate how the below categories (where funding treatment must be agreed) apply to each of the projects currently excluded from funding as crossover projects.

We highlight those areas where we believe that a funding decision and/or a T3 licence condition is required to ensure that the framework allows for appropriate adjustments.

Categories	Funding Treatment
Projects funded by T2 re-openers which were always planned to deliver in the T3 period, and for which T3 allowances were determined as part of T2 re-opener decision; and	No assessment of submitted T3 cost profile required.
Projects funded by T2 re-openers with associated evaluative PCDs that are delayed and will therefore be delivered in T3 rather than in T2.	Gross (direct + indirect) T3 allowances to be set based on original allowance determination (re-profiled if necessary to reflect delayed delivery). T3 licence condition required to hold 'legacy' T2 evaluative PCD with updated delivery date and re-profiled allowances.

Load-related projects funded via T2 Volume Drivers that operate until 31 March 2028 ('T2+2') and will be delivered by that deadline.	<p>No assessment of submitted T3 cost profile required.</p> <p>Gross T3 baseline allowances to be set based on T2 volume driver, with associated baseline outputs.</p>
<p>Projects not funded in T2 which need both T2 and T3 allowances via T3 framework, such as:</p> <p>T3 'baseline' projects, mechanistic and evaluative PCD projects and future T3 re-openers where spend has been incurred in T2 period;</p> <p>Projects that met the criteria for T2 MSIP reopeners but were forecast to incur >50% of spend in T3 period or have only crystallised after final T2 MSIP submission window in January 2025; and</p> <p>Load-related projects that started in T2 but are not funded via T2 Volume Drivers (or any other mechanism) because they deliver Outputs after T2+2 (i.e. after 31 March 2028).</p>	<p>Assessment of submitted cost profiles required as part of T3 Final Determinations (FD).</p> <p>Baseline funding and allowed unit costs for mechanistic and evaluative PCDs to be set for the 'whole' project cost or, if not, the principle must be set out in T3 FD that T2 funding will be made up at T2 close-out to provide the correct 'whole' project cost.</p> <p>Licence conditions for T3 re-openers to capture the fact that funding will be set across both T3 and T2 price control periods.</p>
Projects funded by T2 re-openers with associated evaluative PCDs which were always planned to deliver in the T3 period, but for which T3 allowances were not determined as part of T2 re-opener decision.	<p>Cost assessment needed to set gross T3 allowances and outputs as part of T3 FD.</p> <p>T3 licence condition required to hold 'legacy' T2 evaluative PCD outputs and allowances.</p>
Projects funded in T2 by T2 mechanisms, but Output delivery has been delayed into the first two years of the T3 period and T2 mechanism will therefore automatically remove T2 funding at T2 close-out, i.e. T2 asset interventions covered by T2 mechanistic PCDs and the T2 NARM framework.	<p>No assessment of submitted T3 cost profile required.</p> <p>Gross T3 baseline allowances to be set based on T2 allowances, with associated baseline output, and subsequently treated as a T3 NARM/mechanistic PCD output.</p>
ASTI projects that were excluded from the T2/T3 crossover tab and treated as 'costs outside baseline'.	<p>No assessment of submitted T3 cost profile required as part of T3 FD.</p> <p>Agreed funding to be reflected in T3 licence.</p>
T2 MSIP or LOTI 'Lite' projects where we have made a funding submission but Ofgem has not yet published its decision.	<p>No assessment of submitted T3 cost profile required as part of T3 FD.</p> <p>Assume that these will be assigned evaluative PCDs and phased allowances provided across the T2 and T3 periods.</p> <p>T3 licence condition required to hold 'legacy' T2 evaluative PCD outputs and allowances.</p>

For all of the above, we need to ensure that both direct and indirect costs are correctly funded. This will involve understanding the impact of the T2 Opex Escalator at T2 close-out.

ETQ40. Do you have any views with our proposed approach to ITA project eligibility?

We are fully supportive of the ITA initiative and are keen to pilot it to explore how it can be best applied as part of the regulatory framework. However, we do not agree that there is currently a sufficient level of level of detail provided within the Draft Determination for us to be able to provide a comprehensive and well-considered consultation position on the approach to ITA project eligibility.

We will provide our full and formal position in the detailed consultation post Final Determination.

We are supportive of the proposed approach on ITA project eligibility in principle; however, we need clarity and additional layers of detail beyond the principle itself, to be able to provide well-considered consultation responses.

We note Ofgem's position stated in 4.137 and 4.140 of the Draft Determination ET Annex that it is not possible to define ITA eligibility criteria at this stage and that Ofgem would consult on ITA eligibility considerations as part of the ITA Governance Document consultation following Final Determinations.

Below we provide some initial views on the policy intent provided in Draft Determination:

- We support ITA to be employed for the following types of projects, subject to pre-agreed ITA eligibility criteria:
 - CSNP-F projects
 - tCSNP2 Refresh projects
 - Select non-CSNP load-related projects

We propose an additional category of projects to be added to this list: Select Non-load major projects. These are significant investments of similar scale, complexity and strategic importance as load projects, but the primary driver is non-load/asset health. We believe there is merit in additional assurance and regular engagement with an ITA to ensure reduced assessment time at various submission stages in the project lifecycle.

- ITA eligibility should not be determined by the Authority alone and that eligibility is agreed jointly with the licensees. This is to ensure that we provide early/regular regulatory oversight and transparency on projects that don't strictly meet ITA eligibility criteria as currently proposed, but where there is merit in working together with Ofgem to avoid potential disagreement or disallowances during mature stages of the project. Examples of such projects include where we have tight timelines to meet contracted connection dates for strategically important customers and major projects with non-load drivers.
- We support Ofgem's position stated in 4.136 and 4.142 of the Draft Determination ET Annex that eligibility for the ITA will be assessed on a project-by-project basis from a combination of cost and non-cost criteria. Evaluation will determine project-specific scope, which will vary between projects.
- We are unable to provide a final position on the project eligibility characteristics stated in Table 7 of the Draft Determination ET Annex due to the insufficient level of clarity and the lack of definitions for the terminologies as currently proposed:
 - We support the principle of project complexity and materiality being key eligibility considerations together with cost. However, we believe agreeing clear definitions for terminologies (e.g. how is technological and design novelty defined?) is essential to helping TOs provide well-considered position on this topic.
 - We believe that the strategic importance of a project should be explored further as an eligibility consideration and tested with examples to ensure consistent approach is applied.
- Finally, it will be important to implement the ITA in such a way so as not to cause increased regulatory burden that is not in the consumers' best interest. In developing the policy on ITA further, Ofgem must consider risks associated with proportionality, cost, delay and disputes from the implementation angle.

Ofgem should continue to develop the policy and practical details regarding the ITA to ensure comprehensive and well-considered positions can be provided in the future ITA consultation. As part of this, Ofgem should:

- **Include Non-Load major projects as a category of projects for which the ITA is to be employed**
- **Specific that ITA eligibility is agreed jointly between the Authority and licensees**
- **Provide clear definitions for terminologies linked to project eligibility characteristics**
- **Consider the strategic importance of a project as an eligibility consideration**
- **Consider risks associated with proportionality, cost, delay and disputes in the implementation of the ITA**

ETQ41. Do you have any views on the appropriate information sharing boundaries between the TO and an ITA, and how any conflicts could be managed?

We do not agree that there are sufficiently well-developed, concrete proposals on confidentiality and information sharing with the ITA within the Draft Determination for us to be able to provide a final position at this stage.

In line with 4.140 of the Draft Determination ET Annex, we expect to receive further policy thinking and proposals from Ofgem and to use the detailed consultation post Final Determinations to share our fully considered and formal position on data sharing boundaries for the ITA.

Ofgem should provide, as a minimum, clear and detailed policy proposals on:

- **Specifics around the data/information to be shared with the ITA, including, but not limited to, the nature, volume and granularity of information required**
- **Clear purpose of information sharing**
- **Clear and unambiguous policy proposal on the exact intended use of the information/data**
- **Clear governance plans around information shared with the ITA**

ETQ42. Do you agree with our proposed Carbon Compensation UIOLI to fund carbon offsetting in RIIO-ET3?

We agree with Ofgem's proposal for a carbon compensation UIOLI fund, but do not agree that the proposed funding level for this fund is appropriate given the benchmarks applied by Ofgem to calculate the total are not suitable.

We welcome Ofgem's recognition of the importance of carbon compensation in the Draft Determination. However, in our experience, the current proposal to fund compensation for 6% of our emissions at a benchmark of £44.88/tCO₂e significantly underestimates our carbon compensation ambitions and fails to reflect market reality.

To achieve our goal of delivering a carbon compensation portfolio that is diverse, supports market development, and generates co-benefits for local environments and communities, we believe the following adjustments and considerations to Ofgem's proposal are necessary.

1. Increase of benchmark costs

We have conducted extensive market testing through the development of our Carbon and Nature Framework. This framework currently includes five suppliers offering a variety of credit types and delivery methods, each delivering a range of co-benefits. This diversity provides a representative snapshot of the market and results in a wide range of costs. Based on this, we have calculated an average cost of £74.21/tCO₂e (see NGET_RII03_ETQ42_Funding calculations for details). We note the SPT benchmark of £44.88/tCO₂e and offer the following reasons to support our higher benchmark calculation:

Location and habitat type – Costs vary depending on project characteristics and scale. For example, upland peatland restoration in Scotland benefits from greater availability and economies of scale. Some habitat types also qualify for public grants, which can lower prices.

Credit type and quality – not all credits are created equal. They differ between woodland large scale commercial forestry with limited co-benefits and those from low density deciduous woodland with multiple co-benefits. Co-benefits may include access to nature, biodiversity enhancement, outdoor education, or social value. These credits may also deliver benefits to the environment and/or society through different means such nature-based solutions.

Credit Status - Credits can range in their status, from Verified Carbon Credits (realised carbon benefits) to Pending Issuance Units (future benefits). Our strategy includes both types, prioritising high-integrity credits that deliver co-benefits.

The need for a balanced portfolio – a diverse portfolio will avoid over-reliance on a narrow set of carbon credits that may become unviable or non-compliant with evolving standards and ensure our compensation strategy remains robust and credible over the long term. This was an outcome from our carbon consultation and has guided our development of the Carbon and Nature Framework.

Our ambition to stimulate the market – By investing some of our funding in emerging credit types, (e.g. Wilder Carbon credits), we can support the development of the UK's carbon market, in line with the government's ambition to become a global hub for voluntary carbon and nature markets.

It is important to note that the average price point of £74.21/tCO₂e reflects the full range of prices across all suppliers in our framework. When evaluating suppliers, we focussed on price, integrity, and co-benefits to ensure we selected suppliers that could deliver a diverse and high-quality set of offerings. Including this range of prices (██████████) in our average provides a realistic view of the options available to meet our T3 carbon compensation goals.

2. Increasing the level of investment in carbon compensation

We note that in the Draft Determination, and in its response to DDQ NGET040, Ofgem has used our BCF forecast to determine a carbon compensation investment level of 6%, aligning with SPT's proposal. Our BCF forecast includes Scope 1 and 2 emissions, as well as Scope 3 travel emissions, but excludes Scope 3 capital carbon due to the challenges in forecasting it.

To address this, we have provided a revised calculation in Appendix NGET_RII03_ETQ42_Funding calculations, which uses our FY25 capital carbon intensity and forecast gross capex spend for the T3 period to estimate capital carbon emissions. We have calculated the funding request to the proportion of compensating 10%, a figure we

consider conservative when compared to current SBTi guidance on beyond value chain mitigation for near-term targets.

Ofgem notes, in section 4.152 of Draft Determinations, that SBTi allows a maximum of 10% annual emissions to be offset following reduction and proposes a 6% target for NGET. We believe that using the SBTi Net-Zero Standard 10% threshold as a hard upper limit to proposals on compensation activities is inappropriate for RII0-ET3. This threshold figure is used to achieve a net zero status at target year through offsetting residual emissions, once all necessary carbon reductions have been achieved.

Applying the above criteria equates to £38.53m of funding for carbon compensation over the T3 period. Whilst we acknowledge this is a significant increase in funding compared to T2, we would highlight the unprecedented level of infrastructure investment in T3, an almost 5-fold increase from T2 levels. We also note that the Carbon Compensation UIOLI fund granted for T2 was only for the final year of the price control, rather than the whole 5-year period, so is not a comparable figure.

Importantly, the projected impact on the consumer bill over the 45-year period following T3, is expected to be between £0.01 and £0.03 per year.

3. Provision of UIOLI funding / conditions attached to the funding

There is uncertainty about the future price of carbon credits (as outlined in our EJP). Since the start of T2, prices have doubled. This is for multiple reasons including the rapid evolution of best practice and policy, for example recent UK Government consultation on including Woodland Carbon Code in UK Emissions Trading, which [could significantly increase demand](#) for these units. In view of this and our ambitions to:

- invest in high integrity markets in line with [UK government ambition](#)
- use our funding to drive forward the science and the standards around carbon compensation

Our request is conservative and does not fully account for the rises in credit prices across T3.

For this reason, we suggest that the measure of success for this fund be the sum invested and the quality of credits, as opposed to targeting a specific volume of carbon credits. In taking this approach, we can create a balanced portfolio that delivers against these objectives, and we reiterate our commitment set out in the Carbon Opportunities EJP to follow our 8 carbon principles, to apply a strong external governance framework to ensure we deliver benefits to communities.

4. Stakeholder Confidence in NGET's Carbon Compensation Approach

Our proposed approach and bespoke set of principles on carbon compensation has been informed by engagement with a range of stakeholders. It builds on our T2 strategy, which has evolved since 2020 in response to changing best practice in carbon markets and carbon compensation / BVCM. Further information on this is in our EAP pages 86-91. We have established a carbon compensation steering group which provides strategic oversight of the compensation workstream. In 2023, NGET undertook an external technical consultation with representatives from 20 organisations. This consultation helped shape our approach and development of carbon compensation, including our carbon compensation principles. Finally, we have also consulted Sustainability First on the rises in high integrity carbon credit prices and the associated co-benefits that accompany these credit types (see NGET_RII03_ETQ42_Sustainability First & Wider Supporting information).

Note: Prices are quoted using a 2023/2024 Price Base .

By Final Determination Ofgem should:

- **Revise the benchmark cost to reflect our market tested average price of £74.21/tonne CO2e.**
- **Revise the overall costs to provide compensation that is financially proportionate to compensating 10% of our capital carbon / scope 3 residual emissions during the T3 period.**

ETQ43. Do you have any views on our proposal to reject these two environmental UMs?

We do not agree with Ofgem’s proposal to reject the UIOLI funding for Pot 1: Known low carbon materials and Pot 2: Emerging low carbon opportunities because a centralised fund is more appropriate to simplify, and to avoid gaps in funding.

While we acknowledge Ofgem’s proposal to include Pot 1 within the baseline cost assessment, the absence of a clear mechanism for updating the costs for baseline and pipeline projects (split into 3 distinct project types means that our position remains that a centralised fund would be more appropriate. Such a mechanism will help to deliver carbon reductions on construction projects, whilst ensuring value for money with any unspent allowance being returned to consumers.

We also acknowledge Ofgem’s Draft Determination feedback to consider Innovation funding routes for Pot 2. In response, we have accepted this feedback adjusted the opportunities within Pot 2 accordingly. However, for the remaining opportunities, we do not view there is another funding route or mechanism to deliver these. Therefore, we propose a UIOLI pot to fund known opportunities that have not been tested on our projects to date and to use a reopener mechanism for any other opportunity that might emerge in the future.

By Final Determinations, Ofgem should:

- **approve the proposed £20.1M funding in UIOLI Pot 1 known low-carbon materials;**
- **approve the proposed £36.1M funding in UIOLI Pot 2 emerging low-carbon opportunities; and**
- **approve our proposal to introduce a low-carbon construction re-opener for new opportunities that will emerge during T3.**

These funds will support our contribution towards the NG PLC SBTi target of 37.5% of Scope 3 emissions reduction and other commitments that we set out in our Environmental Action Plan (EAP). We further outline the reasons for requesting these funds below.

1. The needs case for a central UIOLI fund for Pot 1 – known low-carbon materials

The purpose of Pot 1 is to fund the green premia associated with low-carbon materials that are a like-for-like replacement for standard construction materials and have been used on previous NGET projects. We define green premium as the cost difference between standard materials and low carbon alternatives. Therefore this pot will only subsidise this uplift rather than the full price of construction materials.

We acknowledge Ofgem’s position to include these costs within Project Assessment. In our letter to Ofgem on 23rd May 2025, we sought guidance on the treatment of different types of projects:

- Baseline projects with approved funding,
- Volume drivers pipeline projects, and
- Other pipeline projects.

However, we do not agree with Ofgem’s proposal to use Load or CSNP-F re-openers to secure this funding. Given the substantial volume of projects we expect to deliver in T3, it would be inefficient for both parties to use re-openers on project-by-project basis to account for the cost of low carbon materials to each project. Across our ET portfolio, we are expecting the following projects to be potential candidates for the use of low carbon materials

Category	Expected number of projects
Cables	80
Circuit breaker	215
Transformers	143
Switchgear	232
Overhead lines	142
Substation platform	53

Each category listed in the table above has the potential to incorporate the full range of low carbon materials defined in Pot 1. While the specific quantities will vary by scheme, all categories will include concrete and steel elements, and plant activities may be powered by HVO. Given the commonality in the use of these materials, a central UIOLI mechanism would be the most appropriate solution to manage the large number of projects within the NGET portfolio.

In addition, through our post-submission communications with Ofgem (via DDQs and bilateral meetings), we cannot see a clear proposal for an appropriate mechanism to account for this cost uplift at a project level for baseline projects where funding requests have already been submitted to Ofgem.

Given the above, we maintain our position that a central UIOLI fund will deliver the most efficient outcome for consumers.

The benefits of a portfolio level fund are as follows:

- **Strategic procurement:** We support Ofgem's decision to introduce the Advanced Procurement Mechanism¹ to de-risk supply chain for standard equipment and we believe a similar mechanism would be equally valuable for low carbon construction. Access to such a fund would enable earlier engagement with suppliers and foster long-term partnerships. Our experience of delivering the Great Grid Upgrade has already demonstrated benefits of this 'enterprise model' and we would like to extend this approach across our wider portfolio. While some of this funding may be applied to individual projects, we anticipate a significant portion will support initiatives delivering carbon benefits across multiple projects. This is particularly prominent for the ET portfolio of projects that range in size and asset types, making funding through a central pot better value for money.
- **Value for money:** Although these low-carbon materials have proven to reduce carbon emissions, it is not yet possible to determine the exact volume of these materials required for each eligible project. Having a central fund with strong governance will mitigate this issue by ensuring that 'greener' materials are only used on projects where they deliver the most benefit to consumers.
- **Accelerating delivery:** Bulk procuring low-carbon materials will help mitigate long lead times and avoid project delays, hence facilitating decarbonisation of the electricity system.
- **Protection of consumers:** The UIOLI mechanisms ensures any allowance not spent will be not charged to consumers.

2. The needs case for a central UIOLI Pot 2 - emerging low carbon opportunities

The purpose of Pot 2 is to support low-carbon materials and other initiatives that already exist on the market and have proven consumer benefits but have not been trialled on NGET projects. The main difference of this pot 2 compared to pot 1 is the higher uncertainty of cost and volume.

We are requesting £36.1m on a UIOLI basis split proportionally between ET and SI based on the TOTEX spend over T3. Pot 2 will fund the following initiatives:

- Use of low-carbon aluminium
- Use of HV cables made using low-carbon copper
- Roll out of advanced conductors to OHL projects
- Specifying alternative backfill solutions to CBS
- Identifying and specifying uses of ultra-low carbon concretes
- Roll-out of 3D-printed concrete assets across the NGET portfolio
- Modular construction
- Direct procurement/offtake agreement for a small quantity of near-zero-carbon steel

These opportunities outline multiple low-carbon solutions in the transmission network. Low carbon copper and aluminium are available on the market, but we need to further assess and test their suitability on specific asset types, and assess their carbon implications. These materials are known but have not yet been extensively tested within NGET. Additionally, investment in 3D-printed concrete and modular construction represents innovative approaches that can enhance efficiency and sustainability in our projects, with a feasibility study and usage in other industries, respectively, already taking place.

These initiatives will deliver the following benefits: reduced emissions and noise pollution through off-site construction, cost savings from bulk purchasing and standardisation, enhanced project efficiency through the reuse of components, and improved design direction by making early decisions on advanced conductors. Overall, the focus is on supporting innovative materials and construction methods that contribute to a more sustainable transmission network.

Please see NGET_RIO3_ETQ43_Pot 2 emerging low carbon opportunities for a detailed description of these opportunities, their benefits and justification for a UIOLI fund. We acknowledge Ofgem's comment regarding the potential suitability of innovation funding mechanisms, specifically NIA or SIF, to deliver some of these emerging low carbon construction opportunities. We have revised our proposed list of emerging low carbon opportunities that would be better funded via NIA or SIF routes, subject to future Challenges. Examples of these opportunities include:

- Use £50m rapid deployment of proven innovation SIF fund to support roll out of basalt rebar as a steel replacement

- Use NIA allowance to explore substation standardisation
- Apply for SIF funding to study tower redesign to reduce material use and/or extend lifetime, subject to future SIF challenges.

The remaining known opportunities do not fit in the Innovation stimulus funding because of the following reasons:

- They are not aligned with NIA² or SIF³ guidance
- They have a relatively high technology Readiness Level (TRL)
- They have been previously tested in NIA but have not been applied to live projects

As there is currently no alternative mechanism in the RIIO-T3 framework that could support these projects, we believe a dedicated UIOLI Pot 2 to fund low-carbon opportunities that are already known but have lower cost and volume certainty, as opposed to Pot 1 that focuses on materials we have previously applied on our projects, is the most appropriate mechanism.

The justification for having a central UIOLI fund is the same as in the previous section for Pot 1.

Governance framework to ensure consumer value of the UIOLI fund

To ensure transparency and accountability, we have developed a robust governance framework, drawing on stakeholder consultation and informed by insights from the think tank, Sustainability First. The governance model defines roles and responsibilities, provides operational guidance, and set out processes to update the scope to remain fit for purpose. We will work closely with Ofgem and other TOs to:

- Establish eligibility criteria for Pot 1 and Pot 2 focused on initiatives that deliver measurable carbon and wider consumer benefits, and cannot be funded through existing mechanisms, such as NIA, SIF, low carbon construction deployment fund or BAU
- Set up a transparent process for internal project teams to apply for funding specifying minimum participation threshold, where applicable
- Establish a clear route to BAU as the opportunities mature and cost certainty increases during T3.
- Embed sustainability considerations at every stage, ensuring alignment with Net Zero objectives and broader ESG commitments.
- Maintain ongoing evaluation of consumer cost implications to ensure value for money and embed learning, collaboration, and external perspectives into governance.

3. Reopener for emerging low carbon opportunities that will become more certain during T3

We would like Ofgem to consider introducing a low-carbon construction re-opener to provide a clear route to fund emerging low-carbon opportunities that will become viable during T3.

We have taken a holistic approach to designing our construction carbon emissions reduction strategy. Starting from the most certain and known materials all the way to more emerging opportunities. Our current structure includes the following funding routes:

- 1) Pot 1 – a central UIOLI fund for known low-carbon materials that we have previously tested on NGET projects
- 2) Pot 2 – a central UIOLI fund for known low-carbon materials but have not yet used on NGET projects
- 3) Load, Non-load and CSNP-F re-openers – to fund emerging low-carbon materials that are currently low TRL but will become viable during T3. This will only apply to project-specific opportunities that could be added at the Project Assessment stage.

There is a fourth group that currently doesn't have a viable route in the RIIO-3 framework – emerging wider cross-portfolio initiatives that apply to multiple projects and cannot be added to individual Project Assessments. This was one of the underlying arguments for the need of a central Pot 2.

One example of such technology is to invest in our own 3D printing equipment. NGET is currently demonstrating the use of 3D printing of low carbon substation foundations⁴. This project aims to achieve reductions in carbon emissions, reduction in concrete volume and weight, and a more streamlined process. Once proven, there is an opportunity to explore other use cases with our own 3D printing facility. This would not qualify for another innovation stimulus, as this is a scaling exercise and not a novel idea, nor would it be eligible for a re-opener, as multiple projects could benefit from this asset and it will not be fair to make one specific project bear the cost burden.

We are expecting more portfolio-wide opportunities to materialise during the coming regulatory period of T3 and would welcome Ofgem to work together on the design of the most appropriate route to funding for these initiatives.

ETQ44. Do you agree with our proposal to introduce a Non-Load Reopener to address funding gaps in shared-driver projects where the load-related need no longer exists, but an asset health requirement remains?

We agree with the introduction of a Non-Load Re-opener rather than relying on NARM, dual, or top-up PCDs to fund non-load pipeline investments that were not sufficiently mature when submitting our RIIO-T3 Business Plan. It provides necessary flexibility to respond to changing circumstances to ensure required asset health interventions can be delivered.

We do not agree with the current non-load re-opener in the Draft Determinations. By only covering non-load interventions previously linked to load-driven investments, the non-load reopener is too narrow to cover the scope of works we foresee within our pipeline.

We have set out an alternative approach that will enhance the delivery of non-load projects and simplify the overall regulatory framework.

We appreciate the constructive dialogue with Ofgem on this matter, and note that Ofgem is already considering certain revisions to the Draft Determination in response to our feedback.

Ofgem must make the following changes to the Non-Load Re-opener before Final Determination as part of making a workable framework that allows TOs to deliver their asset health plans and maintain a resilient network:

- **Amend the Load re-opener to become agnostic of driver, providing a clear and agile route to funding for major non-load investments in T3.**
- **Enable the re-opener to be triggered when total cost of intervention exceeds the Materiality Threshold.**
- **Provide a route to Pre-Construction Funding to support early development of major non-load projects.**
- **Establish Mechanistic Price Control Deliverables (PCD-M) for lower-value, repeatable investments in the baseline and pipeline, e.g. non-NARM assets**
- **Establish an agile and proportionate funding route for lower value non-repeatable interventions, e.g. via a UIOLI pot.**
- **Establish a RIIO-T3 process for managing projects spanning both price RIIO-T2 and RIIO-T3 controls.**

Overview of NGET Non-Load Plan and access to funding routes

Our RIIO-T3 Business Plan includes a £2bn non-load investment pipeline over five years, covering both repeatable asset interventions and comprehensive site works (see figure 10 below).

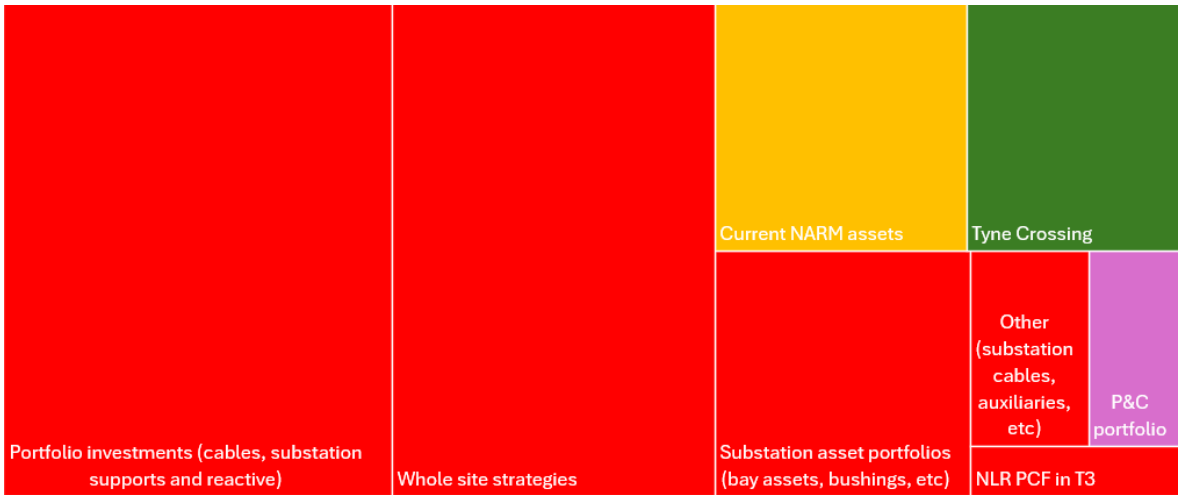


Figure 10: Tree map of non-load pipeline investments

- In green and yellow - approximately one quarter of our pipeline has a proposed route to funding consistent with that established in RIIO-T2 (albeit the funding adjustment mechanism for NARM is not currently workable; please see our response to OVQ5).
- In purple - Ofgem has proposed a mechanistic PCD for the P&C Portfolio, but it is unclear whether this would permit interventions currently in the pipeline to be funded automatically.
- In red - the remaining c. [redacted] does not currently have and requires a route to funding during the RIIO-T3 price control.

Not having a proportionate, agile and flexible route to funding for pipeline projects reduces our ability to respond to

external factors and delivery opportunities as they arise, potentially making our plan less efficient for consumers.

Development Approach

Following Ofgem's feedback, we recognise the importance of providing clarity on the rationale for interventions in the non-load pipeline, as well as outlining the steps taken in developing the plan that led to this outcome. We have set out our non-load plan development approach in the Addendum document "DD01 Asset Health Decision Making".

To limit consumer exposure where uncertainties exist (for example, deliverability considering outage constraints, or the possibility of future site rebuilds), we included the intervention in the pipeline. This approach was based on the expected availability of a suite of uncertainty mechanisms (building on RIIO-T2 mechanisms) which support in-period timely delivery.

Developing our pipeline has required us to balance deliverability considerations with the need to be agile to coordinate asset health interventions with other planned activities to optimise outages and enhance consumer outcomes, especially given the limited nature of system access, supply chain and personnel resources during a period of network expansion. Our approach aims to balance these needs. As stated in Ofgem's ET Annex (5.177), the deliverability of the non-load pipeline during RIIO-T3 is an important consideration, highlighting the need for a flexible regulatory framework. A mechanism is needed to balance consumer value with timely non-load.

Our view of the Non-Load Reopener & Framework

We disagree with Ofgem's proposed narrow scope for the Non-Load Re-opener and the lack of pre-construction funding for non-load major projects.

- **The scope is too narrow, supporting only non-load interventions linked to previous load-driven investments.** Other asset health investments should trigger the Non-load Re-opener regardless of if a load driver was previously associated. For example:
 - All relevant required investments in the non-load pipeline,
 - Non-load components of shared driver projects, which are currently only accounted for within shared driver investments and excluded from the non-load pipeline.
 - Non-load interventions beyond those assets at a single site – especially where opportunities arise to replace assets within the same region, for example when a significant load-related outage is postponed and system access and resources become available.
- **There is no mechanism for early development funding for major non-load schemes and asset replacements.** Unlike the PCF mechanism for load projects, major non-load investment has no route to fund early development Indirect costs. Ex-ante funding for CAI is based on a tightly defined set of baseline schemes which exclude pipeline investments. Therefore, spend on development required to progress these uncertain schemes is entirely at TOs risk until the scheme undergoes cost assessment and total costs can be reviewed and approved.
- **Other risk areas and intervention categories identified by Licensees as needing future funding are not business-as-usual activities** (see page 118 of the ET Annex to DD). Ofgem state high-volume, lower-cost interventions, non-NARM assets requiring intervention and some emergent issues should be treated as business as usual activities to be covered within baseline allowances. Given that the framework has evolved in a way that the majority of allowances are now tied to outputs (circa 90% of investments were tied to outputs in T2 and we expect a similar proportion in T3) TOs lack flexibility to be able to cover and fund these categories through baseline allowances. This is because substituting work is disallowed and funding is withdrawn if outputs for an investment are not delivered. Therefore, TOs will struggle to cover this work through allowances which are not linked to an output. This increases financial risk, especially since historical data shows changes typically occur over seven years. We are concerned to note references⁸ within DDQ responses and the ET Annex suggesting that Ofgem considers TIM as a funding mechanism to be used to cover low materiality unplanned interventions. TIM is an incentive not a funding mechanism.

Our Proposal

Ofgem must ensure that the reopener framework includes all non-load work requiring funding. The following response sets out an approach which would achieve this objective.

⁸ ET Annex – 4.86, ET Annex – 5.37, DDQ075

a. Major Site & Asset Interventions

Major non-load projects and asset interventions should be assessed under a modified Load Re-opener given the protections for consumers in this regime apply equally regardless of driver and the similarities in both processes (like the majority of re-openers) requiring the evaluation of Need, Optioneering/Scope, and Costs. This position is also shared in ETQ29 and the associated Workable Framework paper.

Accordingly, we recommend the following regulatory tools be applied to major non-load investments:

- **Reopener:** Reforming the Load Re-opener to be agnostic of driver. For tools in the Load Re-opener which do not apply to major non-load investments, the applicability of these could be tested and agreed on a case-by-case basis during the Eligibility Assessment stage.
- **Pre-Construction Funding:** To acknowledge the upfront indirect cost of all major projects, extending PCF to all relevant pipeline schemes is a straightforward way to accelerate CAI funding not included in the baseline. The total costs of investments requested at Project Assessment will net off any previously provided PCF allowances to ensure no duplication of funding.
- **Independent Technical Advisor:** Whilst generally we welcome the principles of establishing an ITA, we recognise that the detail is not yet available for consultation. Based on the information we have, we believe major non-load projects would also benefit from this type of scrutiny.
- **PCDs & Licence Obligations:** In fitting with our response provided in ETQ29 and the Workable Framework paper alongside this response, our view is that PCDs should be determined case by case. In the case of non-load portfolio projects, it may be possible to create a Mechanistic PCD to track delivery.

Whilst not our preferred position, if Ofgem does not support these, the scope of the non-load reopener must be expanded to allow eligibility for major asset interventions not addressed by NARM or mechanistic PCDs, otherwise important asset health work will not have a route to funding during the RIIO-T3 period.

Additionally, Ofgem must clarify the policy on value thresholds for submission, other than the standard 0.5% of ex-ante base revenues. As per DD, low value investments could be eligible, which differs from the Load Re-opener that has a UIOLI funding pot for low-value investments.

b. Lower value, repeatable asset investments

We propose Mechanistic Price Control Deliverables (PCD-M) to ensure efficient regulatory oversight for lower-value, repeatable baseline and pipeline interventions – please also see our answer to OVQ13. Such tools would fund uncertain low-value investments, while protecting consumers if interventions are delayed or combined with larger investments. We offer the following suggestions for PCD-M, informed by our RIIO-T2 experience:

PCD-M Suggestion Area	PCD-M Suggestion Description
Non-NARM asset interventions	The PCD-M covers non-NARM asset replacement and refurbishment investments with repeatable scope and unit cost
Final Determination Requirements <ul style="list-style-type: none"> Unit Cost Coverage 	Set baseline funding for a baseline volume, establish an Allowed Unit Cost based on average cost of intervention for each category <ul style="list-style-type: none"> A decision is required: whether unit costs will cover direct capex only or direct + indirect capex. The interaction with the framework for funding Indirect costs needs to be carefully considered. Based on this, the suggestion is for direct + indirect capex.
Grouping Permutations	For simplicity, asset type and intervention permutations can be grouped if the unit cost of intervention is similar (an approach established in T2).
Claw Back Mechanism	If the agreed baseline volume is not delivered, the mechanism can 'claw back' via 'volume x allowed unit cost'. Thus, zero delivery would result in zero funding.
Funding for Additional Interventions	'Volume x allowed unit cost' determines funding for additional interventions delivered for pipeline projects or from load-related projects that are no longer progressing.
Cap on Delivery	If excessive delivery is a concern, a cap could be applied to each asset type permutation and intervention, or on the overall total under each PCD-M.
Reporting <ul style="list-style-type: none"> Unique Assets Annual Allowance Forecasting 	Actual and forecast volumes will be reported during T3 via the annual Regulatory Reporting Pack (RRP) and used to adjust allowances. <ul style="list-style-type: none"> To prevent double funding, each unique asset is linked to a single Licence term; this approach was established in T2. Annual allowance forecasting enables changes to flow through to the revenue pack and drive appropriate customer charging, rather than one end of price control adjustment.

Framework Clarity	We need clarity on the framework and definitions, e.g. what constitutes 'delivered' i.e. is this a single date or milestone?
T2 Framework Improvements	The T2 framework needs to be improved to deal with the transition between price controls and hence avoid the T2/T3 crossover issues encountered.

If this approach is taken, we believe that the following PCD-M could be established in time for Final Determinations:

- Protection & Control – a spreadsheet already provided illustrates how this would work across asset types and interventions.
- Substation assets – e.g. bay assets other than circuit breakers. These are currently captured under Bay Asset and Instrument Transformer PCD-M in T2.
- Overhead line conductor – note that, for this to work correctly, non-load interventions need to be removed from the NARM funding framework as per DD they are covered by both frameworks.
- Tower painting – We believe that painting activity is amenable to a PCD-M, rather than Ofgem's DD suggestion that it should be a PCD-E.
- SF6 management – A proportion of SF6 management funding could be linked to a PCD-M.

Other categories under consideration include:

- **Substation Condition Monitoring Technology** – we are exploring whether Ofgem's suggestion for a PCD-M looks workable.
- **Major Portfolios** - Some 'major portfolios' of work currently within the pipeline could be appropriate for PCD-M following determination, e.g. substation supports. This is dependent on establishing robust, repeatable unit intervention costs – hence why we included a small proportion of substation support interventions in our baseline funding request in order to establish this unit cost.

c. For lower value, non-repeatable asset investments

We propose establishing a UIOLI mechanism under the same principles as the proposed load framework to fund approximately [REDACTED] of smaller projects in the pipeline for which establishing a repeatable unit cost is challenging. For example, substation cables and substation auxiliaries were analysed during the T2 FD, but robust unit costs could not be determined.

ETQ45. Do you agree with our proposed design of the Non-Load Re-opener?

We do not agree with the proposed design for the Non-Load Opener. We have provided the explanation in response to ETQ44, as that question also invited views on the scope of the reopener.

ETQ46. Do you agree with our proposed approach to load and non-load capex assessment, ie the combination of unit cost benchmarking and engineering review? How can the use of expert assessment be further improved?

We do not agree with the proposed approach to Load and Non-Load capex assessment, as improvements are needed in both the engineering review and the unit cost benchmarking.

We explain the improvements needed in:

- NGETQ10 for Ofgem's engineering assessment for load and Non-Load capex;
- ETQ47 for Ofgem's unit cost benchmarking approach.

We explain that there are additional issues with the assessment of these allowances in the following questions:

- ETQ49 for issues within the Project Assessment Model used to calculate the allowances;
- ETQ39 for Issues with Ofgem failing to determine allowances for T2/T3 crossover projects (which is primarily made up of Load and Non-Load capex investments).

Ofgem should address the issues identified with the engineering assessment and unit cost benchmarking approaches identified in NGETQ10 and ETQ47 respectively.

In our SSMC feedback (NGET T3 SSMC ETQ32), we encouraged Ofgem to explore implementing more qualitative assessments with technical experts. This is due to the inherent challenges of statistical benchmarking with a limited data sample. We note this recommendation was not accepted and such qualitative assessments by technical experts have not been carried out.

Ofgem should explore more qualitative assessments with technical experts for future price controls, however we accept at this stage in the process, it is not feasible for Ofgem to add additional assessments.

ETQ47. Do you agree with our approach for unit cost benchmarks? Do you have any views on how the unit cost benchmarking methodology can be improved?

We do not agree with elements of the methodology used in calculating unit cost benchmarks. The approach lacks consistency and transparency and does not reflect like-for-like comparisons or current cost realities.

Our key issues are as follows:

1. Inconsistent risk and contingency percentage applied

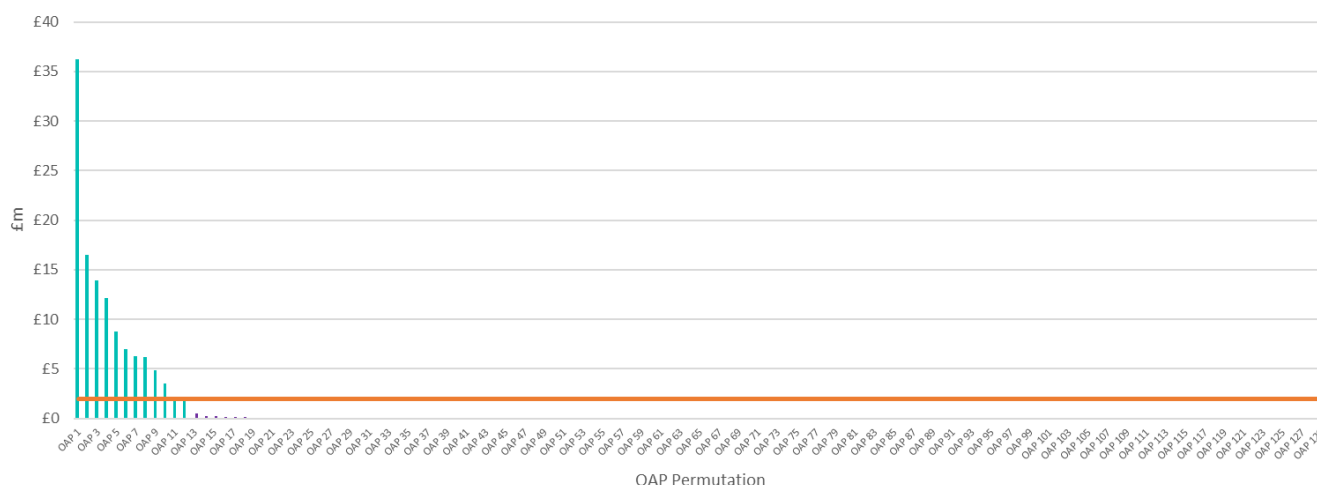
■ [REDACTED]

■ [REDACTED]

4. Not like-for-like comparisons
5. Model, formula and submission clarifications

Our analysis focused on an in-depth review of the 12⁹ Ofgem Asset Possibility (OAP) permutations that resulted in the greatest reductions in allowances due to the cost assessment process. We have included further information about our assessment of these 12 OAPs within Annex NGET_RII03_ETQ47_Supporting Information.

Figure 11: Graph showing the materiality of the 12 OAPs which exceed a £2m disallowance threshold



This approach has enabled us to validate the methodology concerns and errors we identified, and propose the actions which Ofgem must take to correct the issues for Final Determinations. Despite being focused on 12 OAPs, the recommendations we have set out in this response should be applied to the entire benchmarking approach.

The need for consultation on any continued qualitative assessment:

Some of Ofgem's qualitative assessment decisions are erroneous and require adjustments. We detail why this is the case later in this response under the relevant subheadings. However, we are concerned because Ofgem stated in DDQ NGET28 and DDQ NGET44 responses that additional Tier 1 and Tier 1 Targeted OAP permutations will undergo such qualitative assessment following the submission of our Draft Determination response.

The outputs of these further assessments will not have been available for us to review or provide feedback on during the Draft Determination consultation period. There is a risk of errors or misunderstandings from these assessments. Ofgem must provide TOs with the appropriate opportunity to review and respond to any additional OAP permutations being qualitatively assessed. Failure to do so will constitute a clear procedural error. It is therefore essential that Ofgem engages with and consults TOs on its proposals and conscientiously takes the product of that consultation into account ahead of Final Determinations.

Qualitative assessment decisions relied on erroneous unit cost data:

The qualitative assessment involved reviewing the statistical data. Such assessment relies on the original unit cost benchmarking data by OAP permutation, however, as explained below there are errors in this data. As such, the qualitative assessments undertaken to date are not sufficiently reliable to be used as the basis for setting allowances. The published Draft Determinations contained 24 of these reviewed permutations, fourteen of which have had their benchmarks adjusted. Ofgem must rerun previous assessments once the underlying errors in the data are corrected.

⁹ We performed our review for Load and Non-Load separately when deriving at the 12. There are 9 unique OAP permutations among the 12 we reference, as some are duplicated across both Load and Non-Load.

In addition, the errors in the underlying data must be corrected prior to Ofgem conducting any future assessments to ensure that the results are robust.

Ofgem must continue to engage with TOs ahead of taking its final decisions in addition to resolving the following five methodological concerns and errors:

1. Inconsistent risk and contingency percentage applied:

The unit cost benchmarks that Ofgem has calculated are not robust due to inconsistent risk and contingency inclusions among the three TOs. As a result of ambiguity in the RIGs, each TO has taken a different approach to including risk and contingency percentages within their submissions (specifically table 6.1 and 7.1 of the BPDTs).

Ofgem did not account for this by normalising the data before calculating a benchmark, which means that the subsequent benchmarks are not robust. This is an error that Ofgem should address before Final Determinations. SQ NGET202 on 31 July 2025 suggests that Ofgem recognises this issue and is taking the necessary steps to calculate and resolve this.

2. Use of T2 data:

Ofgem has continued to include T2 data despite receiving multiple points of evidence of a structural break in asset costs between T2 and T3 periods. Using cost data before a structural break will result in Ofgem setting allowances which are below the efficient cost, and risks the delivery of TOs plans due to insufficient funding.

A clear change between T2 and T3 costs is evident across multiple OAP permutations. Below are examples from the 12 OAPs investigated in detail:

OAP permutation	T2 to T3 unit cost change
Other switchgear - Switchgear Other - 33kV - Replacement – Each	NGET costs increased by [REDACTED] inclusive of outliers
Wound plant - Transformer - 275kV>=240MVA - Replacement – Each	NGET costs increased [REDACTED]
Fittings - Fittings - 400kV - Replacement – Each	NGET costs increased [REDACTED]
Earth Wire OHL (Tower Line) - Earth Wire - 400kV Replacement – km	ET sector (NGET only) costs increased [REDACTED]
Overhead Tower Line - 400kV OHL (Tower Line) Conductor - Rating >2550MVA - Replacement – km	NGET costs increased [REDACTED]
Wound plant - Transformer - 400kV>=500MVA - Replacement – Each	ET sector (NGET only) costs increased by [REDACTED].
Other switchgear - Busbar GIB (OD) - 400kV - New Build – metre	ET sector costs increased by [REDACTED] inclusive of outliers

For OAP permutations where unit costs have had step change increases as demonstrated above, where the T3 mean increased by more than 50% of the T2 mean, Ofgem should initiate a qualitative intervention. Where TOs can demonstrate the T2 data is not valid, then the T3 data should be used for setting the benchmark. The benchmark variance calculation (which Ofgem currently performs to compare ‘combined’ and T3 benchmark costs) fails to accurately capture this step change. This is because it is impacted by the ‘close year’ issue explained in the following subheading.

3. Year of cost incurred not represented by ‘close year’:

Ofgem uses the ‘close year’ to determine whether a project’s costs fall within T2 or T3. However, this approach can fail to reflect the actual year in which costs were incurred. For long lead items and long duration projects, a cost may have been agreed several years before the project closes. When this data is compared with a more recent project, the cost appears to be more efficient, but in reality this simply reflects differences in market movements between the years and is the driver behind the following 2 OAP permutations being incorrectly benchmarked:

- Overhead - Tower Line - 400kV OHL (Tower Line) - Conductor Rating >2550MVA – Replacement - km - where many of the data points used to build the T3 benchmark were from T2 carryover projects. With these projects, it was often the case that most of the cost activity occurred in T2. (T3 projects flagged ‘T3 funding’ in the NGET BPDT had a volume weighted mean unit cost of [REDACTED], while the T3 projects flagged as ‘T2 Crossover Projects’ had a volume weighted mean unit cost of [REDACTED]).
- Wound plant – Transformer - 275kV>=240MVA – Replacement - Each – [REDACTED]
[REDACTED]
[REDACTED]).

Projects where most of the cost activity occurred during T2 should not be used to calculate the T3 Benchmark. Instead, Ofgem should update its model to use 'delivery year' rather than 'close year' to set the applicable price control period. This is a more accurate reference date for when costs were agreed with suppliers and we welcome further engagement to mitigate for this issue within the data.

Using 'delivery year' would have two implications:

- The unit cost benchmark would be reflective of the price control period where most of the cost activity occurred.
- The variance between the 'T3' benchmark and the 'T2 and T3' combined benchmark would increase, therefore increasing the likelihood that the T3 Benchmark would be selected to avoid erroneous downward adjustments

We recommend Ofgem consider this issue when performing qualitative assessments on high value lines as the timing of long-lead high value components should be a consideration in this assessment.

4. Not like-for-like comparisons:

For some assets, there has not been a like-for-like asset on which to perform the benchmark. Where a statistical check highlights a potential issue, Ofgem needs to consider the following:

Individual project outliers: Due to the nature of projects and the way in which costs were categorised, certain OAPs have outliers. This was discussed at CAWG19 and CAWG21. Despite Ofgem's commitment to exclude outliers exceeding the 100% threshold, data shared at DD shows that several such outliers remain included. This methodological step is necessary to ensure the statistical validity of the data sample used to calculate the unit cost benchmark. From the 12 OAP permutations we investigated, we observe this error within the following:

- Other switchgear - Busbar GIB (OD) - 400kV - New Build - metre - where NGET project [REDACTED] has a unit cost four times greater than the calculated benchmark.
- Other switchgear - Switchgear Other - 33kV - Replacement - Each – There were three distinct outliers. Two were from cost activities which did not align to other data points within this permutation.

Ofgem must repeat the outlier checks and where a unit cost exceeds 100% of the benchmark, those outliers must be assessed separately (i.e. without applying the benchmark used for the rest of the data points for that OAP). We recommend a qualitative intervention to assess these outliers and where Ofgem is limited in the benchmarking it can perform, then the costs should be approved in full.

Data variability due to ambiguous or overly broad OAPs: Technical descriptions of some OAPs are too broad and have resulted in excessive variability within the data to give a robust asset description that can be meaningfully benchmarked. This is evident for the following permutations:

- Other switchgear - Busbar GIB (OD) - 400kV - New Build - metre – Where the permutation does not discriminate between busbars that come from bays, and another much higher standalone cost book item.
- Overhead Line Fittings - Fittings - 400kV – Replacement - Each – Where the permutation does not account for a difference between 'Conductor Replacements' and 'Fittings Only' projects.

Where there is too much variability for Ofgem to accurately benchmark using the current methodology, it must perform a qualitative intervention to explore an appropriate sub-category, and where Ofgem is limited in the benchmarking it can perform, then the costs should be approved in full. For future price controls, Ofgem should explore splitting out these OAP permutations to make the data more consistent per OAP.

TO cost assignment differences: We recommend Ofgem investigate potential cost allocation differences which are driving material differences in the unit costs between the 3 TOs. We identify 3 OAPs with significant variations:

- Wound plant - Transformer - 400kV<500MVA - Replacement - Each
- Wound plant - Transformer - 275kV>=240MVA - Replacement - Each
- Wound plant - Transformer - 275kV<240MVA - Replacement - Each

Through a detailed CAWG, Ofgem could validate whether these have been costed differently by each TO. Our preliminary investigation with other TOs suggests that they have allocated costs over multiple OAPs, whereas NGET has grouped all transformer-related costs under a single OAP. The impact of this is that NGET will appear to have a higher unit cost (even where total project costs for the same activities are very similar) and would therefore receive lower allowances purely because of this difference. Ofgem must correct the data to account for this.

In addition, Ofgem should verify whether the scope of a replacement (i.e. a volume count of '1') is a whole transformer, which is how NGET reports, or can represent sub-components being replaced, which other TOs have historically reported.

The root cause of such variation is that, despite working cooperatively on the Transmission Glossary, there remains a degree of ambiguity in the interpretation of definitions.

5. Model, formula and submission clarifications:

There are miscalculations in Ofgem's unit cost benchmark models, which we have already communicated to Ofgem via Gitlab. An extract of this is included in Annex NGET_RII03_ETQ47_Model and formula errors.

In addition, upon reviewing how Ofgem have calculated the unit cost benchmarks, we have identified OAPs which require data input adjustments due to the data categorisation:

- Earth Wire - OHL (Tower Line) - Earth Wire - 400kV - Replacement - km – The approach we took to populate the Load data is impacting the unit cost benchmark Ofgem calculates. Therefore, we will adjust the volumes for the Load data to facilitate a robust benchmark.
- Other switchgear - Switchgear Other - 33kV – Replacement - Each – There was an outlier for the project [REDACTED] cost would be better allocated against a shunt reactor OAP permutation.

To mitigate the above two points, NGET will supply to Ofgem a file with the impacted schemes with reclassified OAPs and updated volumes. This will be supplied after the publication of our Draft Determination response. We recommend that Ofgem calculate a new benchmark based on this new data and use the revised benchmark for all projects within the affected permutations.

Conclusion

Notwithstanding the above, we recognise the improvements Ofgem has made since the T2 unit cost benchmarking process, such as breaking out the permutation into "new build, replacement, major refurbishment etc." as detailed in ET Annex 5.23.

To resolve the remaining issues, Ofgem must review the above points and examples we have identified to make any necessary corrections in terms of both methodology and OAP benchmark adjustments. Ofgem must also give NGET sufficient time to meaningfully review and respond prior to Final Determinations.

Once T3 has reached Final Determinations, Ofgem should undertake a 'lessons learned' process with TOs so that future price control submissions can be more standardised. This will reduce data variability between TOs and for each OAP to better support benchmarking.

For further information on each topic and the 12 OAP permutations, please see NGET_RII03_ETQ47_Supporting Information.

ETQ48. Do you agree with our proposal to roll-up unit cost benchmarks and set the benchmarks at the scheme level?

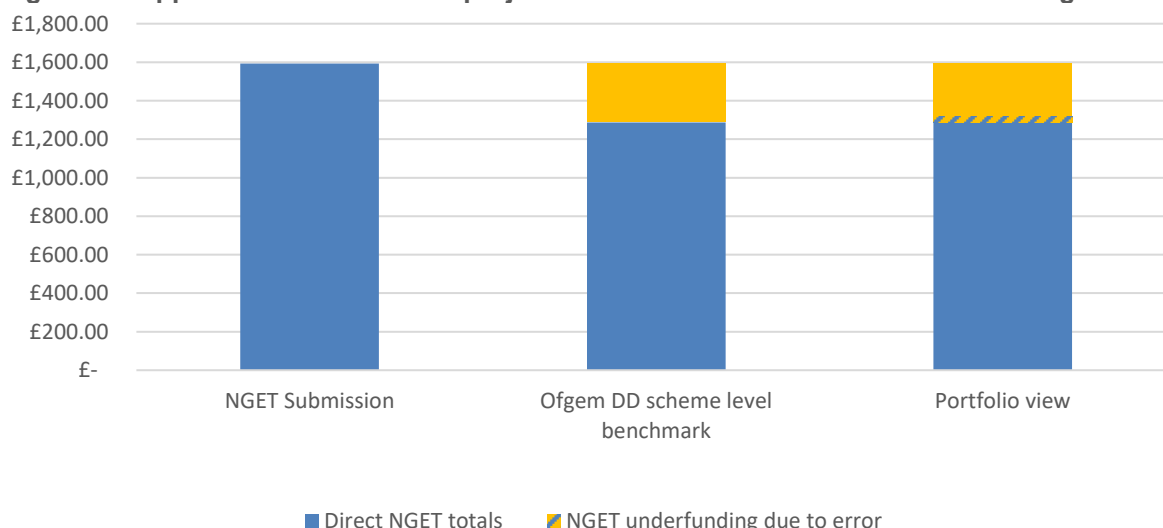
We do not agree that rolling up unit cost benchmarks and setting them at the scheme level fully resolves the issues with PAM. While we recognise this change as a positive enhancement that addresses some of the concerns we have raised since T2, it remains insufficient and continues to result in underfunding.

The mechanistic downward adjustment introduced to T2 PAM is a mathematical error within the PAM model. Ofgem's DD position of scheme level benchmarks does reduce the impact of this error, but it is only capped at scheme level and still allows for significant errors across the portfolio.

In preparation for T3 through discussions at a cost assessment working group, Ofgem explored rolling-up the unit cost benchmarks to a more aggregated scheme or portfolio level. This engagement was welcomed and showed that Ofgem recognised the error in its approach and was trying to resolve it. However, the error remains and still exists at a more aggregated level.

The current logic avoids multiple downward adjustment calculations performed across all assets within a scheme, but it is still performed once at each scheme. When repeated for all schemes across the portfolio, this becomes a significant mathematically invalid approach for the roll-up and setting of allowances. To quantify this, we performed a test with our Load and Non-Load assets in PAM for the approved baseline projects, concluding it caused £30.8m of underfunding:

Figure 12: Approved baseline NGET project values in PAM for Direct costs excluding 'Other'¹⁰



Ofgem must update PAM to further roll-up the benchmark to portfolio level. Regardless of whether this update is implemented, a robust roll-up requires the unit costs of assets to be benchmarked accurately. Therefore, Ofgem must address our unit cost observations outlined in ETQ47 to ensure this works as intended.

¹⁰ Figure 12 category description:

- TO submission: Value NGET originally submitted
- Ofgem DD scheme level benchmark: Value after reductions such as benchmarking, risk % change and volume adjustments.
- Portfolio view: Ofgem symmetrical benchmark takes precedence after reductions for risk % change and volume adjustments. If no benchmark then TO submission value is used

ETQ49. Do you agree with our continued use of the PAM? How can this be further improved?

We do not agree that PAM is a suitable primary cost assessment tool for Load and Non-Load capex.

We continue to have four substantive concerns with the ongoing use of PAM:

- **The model relies on a highly granular set of unit benchmarks that cannot be robustly populated**
- **The model is overly complex**
- **The model contains errors**
- **The model is not suitable for re-openers**

While we acknowledge the significant enhancements to the PAM when compared to T2, our long-standing concerns about the use of PAM remains unresolved¹¹. It is unrealistic to expect Ofgem to adopt our preferred methodology at this late stage of the price control cycle, however, we view that there is still scope to improve PAM to achieve a suitable calculation of Load and Non-Load capex before Final Determinations. We therefore offer constructive suggestions to refine the model and mitigate its limitations.

Looking ahead, Ofgem should also explore and seek enhancements and alternatives for future price controls, as we do not agree that the continued use of PAM is an ideal way to undertake a robust quantitative analysis of Load and Non-Load capex costs when we have additional qualitative information per scheme.

The model relies on a highly granular set of unit benchmarks that cannot be robustly populated

At its heart, PAM performs an analysis of how the unit costs for specific interventions proposed by TOs compare to a benchmark cost for that activity. We set out in ETQ47 our response to Ofgem's approach to unit cost benchmarking.

There are over 150 OAPs, each with multiple intervention types (addition, new, replacement, major refurbishment etc.). As quantified by Ofgem in CAWG19, this leads to 910 potential permutations, 229 of which had a T3 funding request by at least one TO.

Each of the three TOs apportion their investment plans into these permutations. Consequently, there are too few parties dividing their activities across too many permutations to arrive at robust benchmarks for the majority of permutations. This leads Ofgem to make inappropriate decisions - such as that set out in paragraph 5.24 of the ET Annex - where it relies heavily on historical data to increase the amount of data within the data set.

Through the Draft Determination Ofgem acknowledges several times that it struggled to find the data to support its objective: "*where data availability and consistency made it possible...*" (para 5.24); "*this was not possible due to data availability, or not viable due to cost volatility*" (para 5.25); "*where assets and non-assets lacked a sufficiently robust dataset to derive any benchmark*" (para 5.25); "*submitted costs from the TOs for each benchmarked asset varied considerably*" (para 5.27).

However, if the number of permutations were reduced to enable more TO data per OAP, there would be further risk that the benchmarks are comparing dissimilar projects.

This inherently deep quantitative exercise was categorised as 'bespoke' rather than 'comparative' for the purpose of undertaking the Stage B Business Plan Incentive assessment. This implies that Ofgem recognised it was not able to perform the quantitative comparative analysis at the heart of a robust benchmarking exercise.

It is for these reasons that that we put forward the suggestion in our SSMC response that Ofgem consider a 'stratified random sampling approach' rather than the continued use of PAM.

¹¹ Discussed in Cost Assessment Working Groups 4, 7 and 16 on 17/01/24, 27/02/24 and 14/11/24 respectively, in our SSMC response and T3 submission within Section 2.2.3 of Annex A14 Cost and Benchmarking.

The model is overly complex

The PAM model used to calculate Load and Non-Load capex allowances is highly complex, comprising 30 interlinked worksheet tabs, as illustrated in Figure 13. Each line in Figure 13 demonstrates where two worksheets are linked through at least one formula. Such a complex model causes difficulties when we try to assure the quality of the results to be confident that the results are robust. Such complexity also substantially increases the possibility of Ofgem making an error.

Figure 13: Visual of worksheet relationship within PAM model



The model contains errors

We have highlighted to Ofgem through the Gitlab process the arithmetical errors we have uncovered through our analysis and which must be corrected. Such errors ranged from the systematically incorrect treatment of risk and contingency allowances that were erroneously double-counted by Ofgem to individual cells that were not copied across correctly.

There is one error remaining within the PAM model which needs addressing, and some of the inputs to PAM should be amended as outlined below if Ofgem intends to rely on the PAM at Final Determinations. This error is detailed within our ETQ48 response where we outline that the only mathematically correct approach is to perform a portfolio assessment of costs rather than at scheme level.

In addition, the inputs which need amending are the engineering and unit cost inputs into PAM, which we outline in NGETQ10 and ETQ47 respectively.

The model is not suitable for re-openers

Though we believe that given tight timelines Ofgem could make suitable adjustments to the PAM model, to use it for Load and Non-Load capex for T3, it would not be acceptable to use PAM to perform project assessments for re-openers.

The model relies on a substantial data set and so it is not appropriate to compare a single project submitted outside the main price control submission to that original data set. The benchmarks may be outdated by the time of a re-opener, and an individual assessment, as provided for under ASTI, CSNP-F and LR re-openers, can be performed more accurately if undertaken properly.

Conclusion

In our response to the T3 SSMC, we raised three major concerns about the quality of a cost assessment involving PAM. In the below table we set out our position against each concern now having reflected on Ofgem's Draft Determinations and how this has evolved:

NGET Initial Feedback reflecting on T2 (Response to SSMC ETQ31)	NGET observations after assessing T3 DD
There were serious statistical shortcomings to the ET2 approach, for example insufficient data points to constitute a statistically valid sample for the majority of asset categories	<p>We acknowledge the efforts of Ofgem's cost assessment team to seek robust data and apply transparent criteria.</p> <p>We believe further focus is required to ensure the PAM should only be used where statistically valid data populations are available, i.e. where multiple data points exist, it is a repeatable activity, there is low technical variation in scope, and there has been stable cost data / low volatility historically.</p> <p>Our reflections on OAPs of concern are included within ETQ47.</p>
There were data consistency issues with the ET2 approach, for example outliers were not removed from asset categories resulting in asset types not being assessed on a robust "like-for-like" basis	<p>We remain unconvinced that there is a robust source of data to perform the purely statistical analysis for benchmarking that PAM performs. Examples are seen in ETQ47 where we highlight certain OAP permutations we believe need further refinement.</p> <p>Such challenges will persist if PAM is used as the preferred tool for future price controls and so we advocate further enhancements to standardise reporting definitions.</p>
Ofgem's intended allowance setting approach was mathematically flawed to such an extent	We recognise the engagement of Ofgem to try and resolve this point, which was a major concern for NGET throughout the

that even an efficient company could not recover efficient costs. This was due to the methodology choosing the lower of ET1 actual costs or ET2 submitted costs, and the mechanistic downward adjustment of allowances in any project where submitted costs were higher than the benchmark, yet allowing only submitted costs where such costs were below the benchmark	working groups prior to DD. Our reflections are shared within ETQ48 where we explain how a portfolio assessment is the only mathematically correct solution.
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Ofgem must resolve the unit cost benchmarking issues raised in ETQ47, as unit cost input is a vital driver for the outputs of PAM.

Ofgem must also address the engineering assessments that underpin the volume assumptions in PAM, which are covered in NGETQ10.

For future price controls, Ofgem should examine whether the current approach allows the robust quantitative comparison that it seeks to perform and whether alternatives such as stratified random sampling would perform better.

ETQ50. Do you agree with our proposed approach for setting the R&C allowance? If not, why? Please outline any challenges that you think might be present with our proposals on the R&C allowance and the interplay with the TIM.

We do not agree with the proposed approach for setting risk and contingency allowances as set out in Draft Determinations, which results in a shortfall in allowances of over £340m. We believe that the approach is flawed as it is overly simplistic, based on neither robust evidence or modelling, and erroneously conflates setting appropriate allowances for projects with wider regulatory incentive mechanisms such as the Totex Incentive Mechanism.

However, we welcome Ofgem's decision to discard the use of a reopener or a UIOLI fund for risk and contingency costs, which would increase regulatory burden and uncertainty at the outset of a project. Well-calibrated and evidenced ex-ante allowances are the appropriate means to fund those elements of project risk that cannot reasonably be mitigated or insured; and in order to deliver a workable and investable framework across our project portfolio that meets consumer requirements for delivering investment at pace.

Ofgem's approach to risk and contingency allowances is a critical determinant of overall portfolio risk. While the Draft Determination is right to set ex ante allowances, the level at which these have been set is wrong for the following reasons:

- **It is an error to impose an arbitrary and overly simplistic risk and contingency allowance that is too low.** Despite two DDQs, Ofgem has been unable to present modelling analysis for the 5% risk and contingency allowance that is proposed. Our approach – guided by project specifics – is detailed and based on a wealth of empirical evidence. Our results - externally validated and in line with global industry best practice – suggest a much higher risk and contingency allowance is appropriate. In T2, the analysis that supported the 7.5% cap contained methodological errors (discovered in February 2024). The lack of transparency around how Ofgem has now estimated 5% is not in line with required regulatory practice and standards, particularly for such a material cost item.
- **Ofgem also erroneously conflates setting appropriate allowances for projects with wider regulatory incentive mechanisms such as the Totex Incentive Mechanism (TIM).** The specific design proposals for TIM do not justify setting unevidenced and inappropriately low risk and contingency allowances. However TIM is set, it will only operate as intended if the level of allowances represents a fair bet. We also disagree with the suggestion that a stepped TIM approach would protect TOs where they have encountered high-cost risk event outside of their control, as networks are exposed to the first 15% of overspends at varying rates of sharing (up to £600m for NGET).

The net effect of this is a material under-funding of necessary and efficient costs that can be expected in RIIO-T3. Assuming Ofgem's proposed 5% cap is applied to all risk and contingency over £100k in RIIO-ET3 as is proposed, this would result in £343m of disallowed funding across our baseline (58% of the total evidenced risk) and £1.8bn across our pipeline.

Considering the downside risk that NGET faces across multiple components in the price control (FQ17), including input cost risk that RPEs are only able to partially mitigate (OVQ18), and the risks facing any organisation expanding its delivery rate by two and a half times in such a short period, higher risk and contingency allowances are required.

This funding gap represents a disproportionate and unacceptable risk for NGET. As such, it is important to establish the principles for appropriate and proportionate setting of allowances for risk and ensure that an arbitrary cap assumed during the Final Determinations is not then applied to all reopeners throughout the price control. On the whole, Ofgem's proposed approach results in heightened risk for NGET, which will negatively impact investibility.

We provide further detail in the supporting evidence below which confirms that Ofgem's allowances are too low. In summary:

- For projects in progress, we have estimated a project-specific risk and contingency amount using the P50 value from Monte-Carlo analysis, in line with the guidance set out by the IPA Cost Estimating Guidance.
- For less mature projects, we have used historical additional costs incurred throughout the project lifetime from a representative pool of £2.4bn of projects to estimate appropriate risk and contingency funding. We estimated risk and contingency values for different categories of work, which given the expected T3 mix of projects led to an overall estimate of █████ of project costs. This estimate reflects what we see in other appropriate external benchmarks i.e.:
 - Parsons Brinckerhoff IET Electricity Transmission Costing Study found 10-15%¹².
 - Mott MacDonald in conjunction with the IET found 8-9%.¹³

¹² The IET: Electricity Transmission Costing Study <https://www.theiet.org/media/9376/electricity-transmission-costing-study.pdf>

¹³ The IET: A Comparison of Electricity Transmission Technologies: Costs and Characteristics <https://www.theiet.org/media/9376/electricity-transmission-costing-study.pdf>

- We also note that Ofgem has allowed 10% risk and contingency allowed to gas transmission in RIIO-3 Draft Determinations.¹⁴

Correcting this in the Final Determinations is critical for ensuring robust cost-benefit analysis; reducing the risk of cost overruns undermining public and investor confidence; and delivering an overall regulatory package that is workable and financeable.

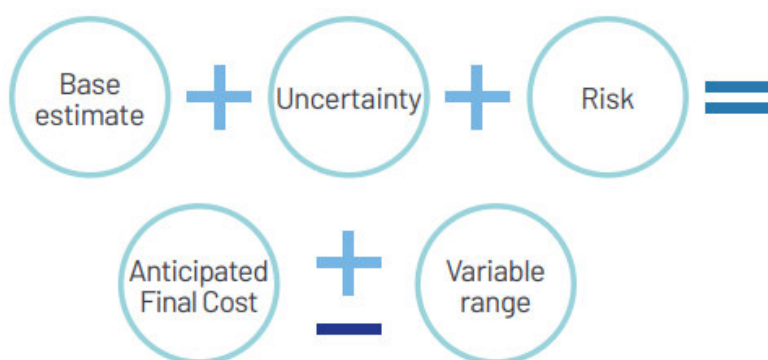
For Final Determinations, Ofgem must increase risk and contingency allowances across our baseline projects:

- **For mature projects**, Ofgem should allow the project-specific risk and contingency costs that we estimated in our Business Plan.
- **For less mature projects where it is not yet possible to estimate project-specific risk and contingency costs**, Ofgem should set a risk and contingency allowance of [REDACTED].

Supporting Evidence

Accurate cost estimation is critical for the successful planning and execution of capital projects. The Infrastructure and Projects Authority, in its Cost Estimating Guidance¹⁵, defined the cost estimation equation as follows:

Figure 14: Infrastructure and Project Authority Cost Estimation Equation



Estimating the Anticipated Final Cost as robustly and reliably as possible will ensure that the Anticipated Final Cost is representative of the most likely outcome. The IPA's Anticipated Final Cost is therefore akin to the standard Ofgem should be striving for when setting regulated cost allowances.

This is critical when setting allowances for three reasons:

- To ensure that the consumer outcomes delivered by the project outweigh the cost of investment;
- To ensure that consumers and networks are not exposed to cost and schedule overruns associated with poor estimation, which risks leading to a loss of public confidence in the legitimacy of the regulatory framework, and will also undermine investor confidence; and
- By correctly setting the allowance, an efficient company can deliver to allowances setting the correct start point for any sharing incentives to be triggered.

It is an error to discard TO evidence and impose an arbitrary risk and contingency allowance of 5%.

Within the Draft Determinations, Ofgem presents no modelling analysis to support the 5% that is proposed. We raised DDQ042 to clarify how this figure was derived, and Ofgem noted that it was based not on modelling but on a range of factors including submissions from network companies as well as externally commissioned research.

This research was shared with us following our request DDQ065. The decision to retain ex-ante allowances was arrived at through a qualitative review but no evidence of the quantitative analysis undertaken to derive the 5% was included in the review. Furthermore, we see no logic of setting of risk allowances at 5% of scheme's direct costs

¹⁴ Ofgem: RIIO-3 Draft Determinations – National Gas Transmission
<https://www.ofgem.gov.uk/sites/default/files/2025-06/Draft-Determinations-Gas-Transmission.pdf>

¹⁵ The Infrastructure and Projects Authority: Cost Estimating Guidance:
https://assets.publishing.service.gov.uk/media/6050c9528fa8f55d324b0c84/IPA_Cost_Estimating_Guidance.pdf

where the associated risk is higher than £100k, and those risks below £100k being allowed in full.

Our experience in RIIO-T2 was that the analysis used to estimate the 7.5% risk and contingency cap contained two methodological errors:

- No weighting was given to project size – a simple average of risk percentages was taken across projects;
- The simple average included 10% of entries with a risk value of 0% (because of the early-stage nature of the project). If these values were excluded, then the simple average would have been 8.4%.

We were provided with redacted analysis to underpin the value in February 2024, three years after Final Determinations were published. We are concerned that similar methodological errors may be being made at RIIO-ET3.

Ofgem states in Draft Determinations that the approach to setting risk and contingency has been applied to “a *relatively small share of schemes*”¹⁶. Our experience throughout the RIIO-T2 price control period has been a consistent application of a cap of 7.5% to risk allowances. We are concerned that the approach proposed in Draft Determinations will continue in T3, capping risk at 5% on all projects and imposing a significant and unrealistic challenge against all future re-opener submissions.

Impact of Ofgem’s proposals

Draft Determinations propose a £100k threshold to allow in full some risk and contingency costs associated with projects. When we apply this to our business plan submission, it equates to £10.5m of risk allowances, being **1.7% of the total value requested**.

Where a project risk exceeds £100k, Ofgem is proposing to set the allowance at 5% of the direct cost of the project. This is significantly below the historic rates we evidence below. By applying this approach to our baseline business plan submission, we can see that we would be awarded £237.3m.

When combined with the below £100k risk being passed through, we would be awarded a total of £247.8m, giving rise to a shortfall in funding of [REDACTED] or 58% of the total evidenced risk. Moreover, based on the size of our pipeline, adopting the methodology proposed at Draft Determinations would result in [REDACTED] of disallowed risk funding.

On the whole, Ofgem’s proposed approach results in heightened risk for NGET, which will negatively impact investability.

Our evidence-based approach to quantifying risk

We outlined our approach to quantifying risk in our A14_Cost Assessment and Benchmarking Approach Annex submitted with our December 2024 business plan.

Our approach – guided by project specifics – is sophisticated, detailed, based on a wealth of empirical evidence, externally validated and in line with global industry best practice. It has been shared in full with Ofgem to allow complete scrutiny and validation.

Our submitted plan contained a combined risk and contingency element of [REDACTED] in the T3 period, against a total T3 request of [REDACTED] within the baseline. These projects were included in our baseline submission because they were deemed to meet the tests set out in Business Plan Guidance on confidence in costs, timing and volumes.

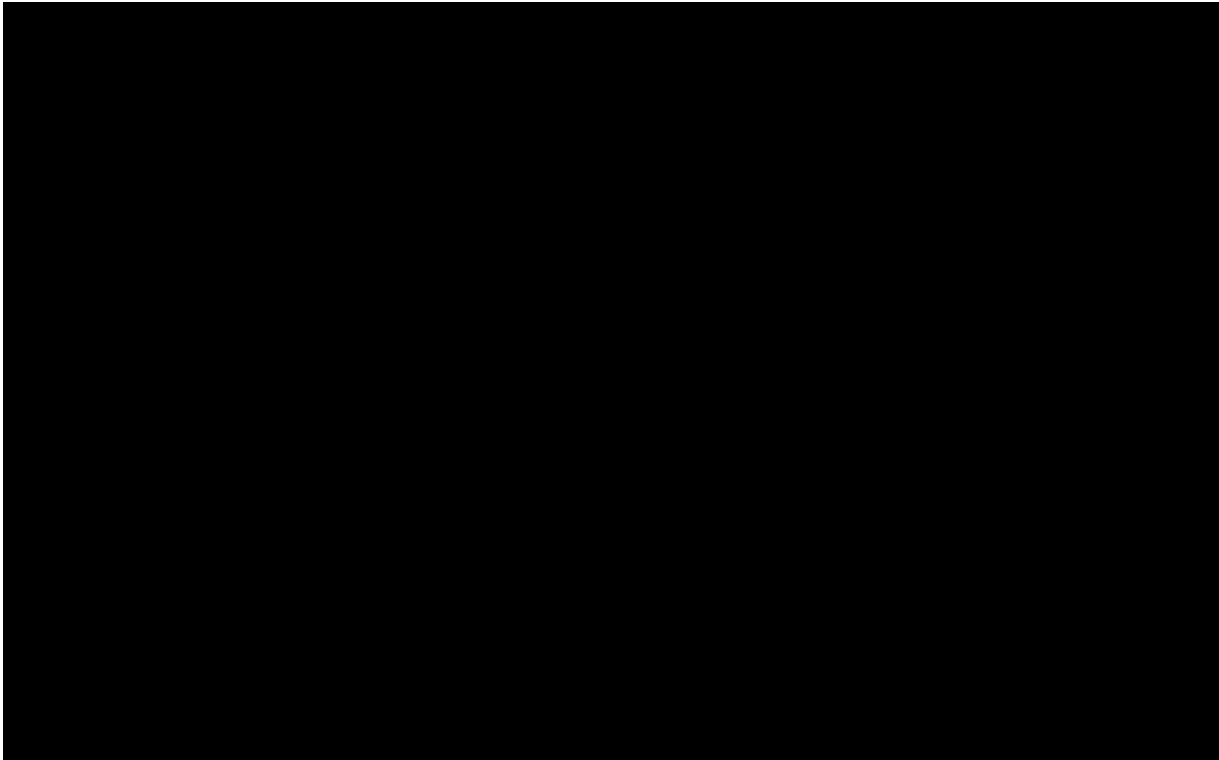
Whilst projects have met the criteria for cost maturity, this does not mean that risk has been eliminated. We can have a degree of confidence generated either by their maturity in development or by the repeatable nature of the work. This means we are able to estimate this uncertainty through recognised techniques such as quantitative risk analysis (for those projects already mature and in the delivery phase) or through recognised evidence-based approaches (such as method of moments). Our submitted baseline business plan contains projects with a mixed level of maturity - 6% of spend is on projects in progress while 94% is for projects that have not started.

When assessing the forecast risk, we adopted two approaches:

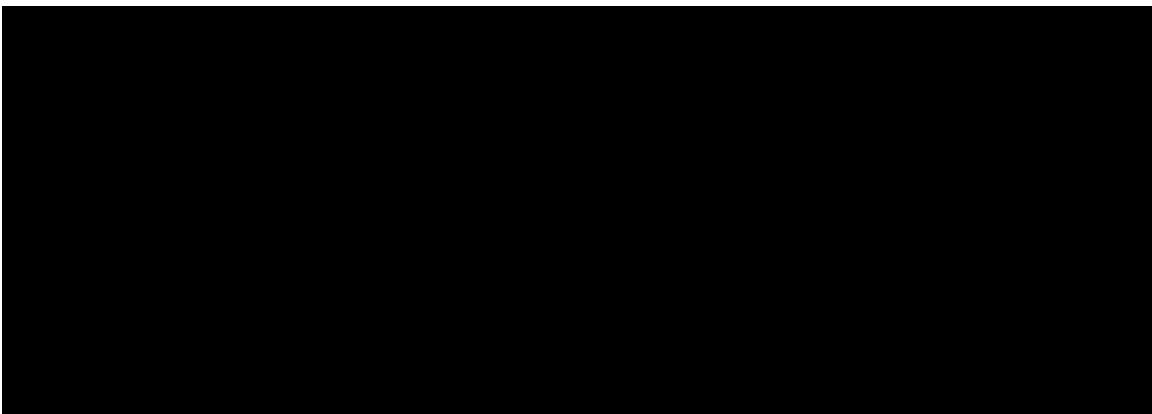
- For those projects in progress, our quantitative cost risk management process provides a structured and systematic approach for identifying, analysing, and evaluating risks based on objective data and metrics.
 - Using this approach, a project-specific cost estimate has been prepared. There is a unique risk register associated with each project, and a project-specific risk and contingency amount is included in the overall project cost reflecting the risks identified.
 - When compiling the risk registers, our project teams review the programmed activities still to be

¹⁶ Para 5.37 Electricity Transmission Annex

- completed and assess the risks and uncertainties associated with these activities.
- As part of considering the risks, we consider the cause, impact and probability as well as three cost values – Minimum, Most Likely and Maximum and the mitigation complete and remaining mitigations to complete.
- These risks are then captured in an externally provided software package – Predict! @Risk, which computes many different possible scenarios through Monte-Carlo analysis.
- This approach produces a probabilistic curve showing the expected risk value in varying scenarios.
- We use the P50 value as the most likely value for inclusion in our estimates. This is in line with the guidance set out by the IPA Cost Estimating Guidance, as shown in Figure 15.
- As projects progress through to completion, risks will either crystallise or be mitigated and so taking a view of risk mid-project will give a misleading view when applied to a portfolio that has projects at various points in their delivery cycle.



- For those less mature projects, where this comprehensive risk assessment process has not yet started, we used historic project outturns to develop a likely profile of risk materialisation to incorporate into a most likely project estimate.
 - We analysed a representative pool of completed or largely completed projects ranging from £10m to £300m to identify the additional costs incurred from the point of contract award to completion, attributable to risks crystallising during the project execution.
 - These projects were taken from both our Load and Non-Load portfolio to ensure that differing external stakeholder driven risk was taken into account.
 - We also identified that differing working environments impact the risk profile, for instance, work on overhead line projects encounter multiple landowners with risks associated with negotiating access compared to asset replacement within a National Grid controlled substation compound.
 - This analysis covered £2.4bn of contract award. The analysis, once adjusted to remove inflation from the contract price evolution, showed a scatter of projects as illustrated below.



- [REDACTED]
- [REDACTED]
- Having concluded this exercise, we then tested this against the IET Electricity Transmission Costing Study undertaken by Parsons Brinckerhoff¹⁷. This identified a build contingency range of between 10 – 15%.
- A similar exercise was undertaken by Mott MacDonald¹⁸ in conjunction with the IET, and this showed a range of 8-9%.

Regulatory inconsistencies

Despite the similar characteristics and nature of capital projects being undertaken between Gas Transmission and Electricity Transmission, Ofgem has proposed a substantial difference in risk and contingency allowances, with T3 Draft Determinations in Gas Transmission¹⁹ proposing to retain the 10% risk and contingency allowed in T2.

If the Gas Transmission approach was applied to our submitted business plan, it would result in [REDACTED] of funding towards risk and contingency. Whilst this still imposes an additional efficiency challenge on the TOs, it is a more proportionate approach than that currently proposed.

The Draft Determination inappropriately conflates efficient ex-ante allowances with performance incentives

We also have concerns in relation to the interaction between the R&C proposal and TIM.

We agree that the changes proposed to TIM do not directly affect potential risk and contingency costs arising for individual projects. However, we disagree with the suggestion that a stepped TIM approach would protect TOs where they have encountered high-cost risk events outside of their control and that TOs would be compensated completely.

Networks are exposed to the first 15% of overspends at varying rates of sharing. When applying the proposed TIM mechanism to NGET's submitted business plan, NGET may not be compensated for the first **£600m** associated with cost overruns.

Ofgem has stated that it thinks the stepped TIM approach also “*balances the need for regulatory certainty with the perceived downside of not providing as high an R&C allowance as in RIIO-ET2.*” We disagree with this statement. The need for regulatory certainty is best met by providing appropriate compensation for risk and contingency based on evidential analysis, rather than being wrapped into a regulatory mechanism that introduces more uncertainty depending on the relative position of the portfolio costs against allowances in the year that the high-cost event occurs.

TIM was introduced to encourage networks to improve efficiency in delivery and ensure that the benefits of these efficiencies are shared with consumers. It also provides some protection to companies from overspends as the cost of overspends are also shared with consumers.²⁰ The figure below demonstrates the layers of protection provided through the framework for both consumers and network companies. The Ofgem position appears to place greater emphasis on the lower levels of protections from overspends, rather than address the risk more directly through an evidence-based approach to setting of R&C allowances. Whilst we agree that the proposed changes in TIM provide more protection to networks from overspends, they do not remove the risk.

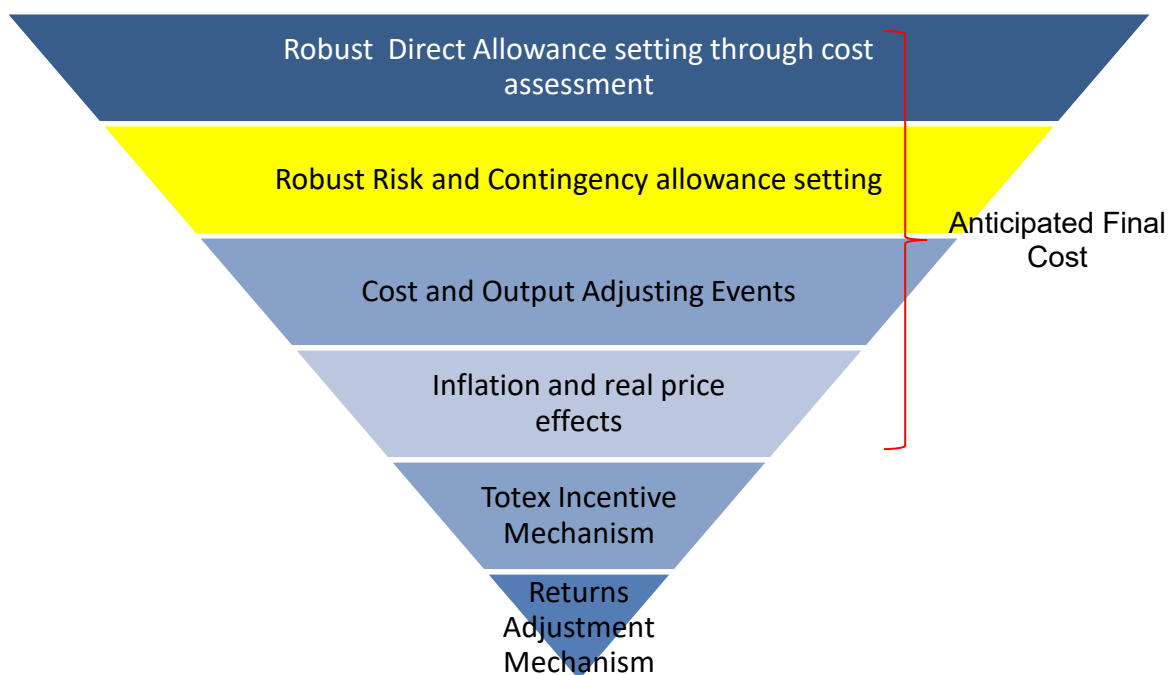
¹⁷ The IET: Electricity Transmission Costing Study <https://www.theiet.org/media/9376/electricity-transmission-costing-study.pdf>

¹⁸ The IET: A Comparison of Electricity Transmission Technologies: Costs and Characteristics <https://www.theiet.org/media/9376/electricity-transmission-costing-study.pdf>

¹⁹ Ofgem: RIIO-3 Draft Determinations – National Gas Transmission <https://www.ofgem.gov.uk/sites/default/files/2025-06/Draft-Determinations-Gas-Transmission.pdf>

²⁰ Ofgem: RIIO-2 Final Determinations - NGET Annex (REVISED) https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determination_nget_annex_revised.pdf

Figure 17



For Final Determinations, Ofgem must increase risk and contingency allowances across our baseline projects:

- For mature projects, Ofgem should allow the project-specific risk and contingency costs that we estimated in our Business Plan.
- For less mature projects where it is not yet possible to estimate project-specific risk and contingency costs, Ofgem should set a risk and contingency allowance of [REDACTED].

ETQ51 Do you agree with our assessment approach for Vehicles and Transport and Non-operational property? If not, how do you consider we should assess these costs?

We agree with Ofgem's cost assessment approach for Vehicles and Transport and Non-operational property.

We appreciate that Ofgem has recognised the step change between RIIO-T2 and RIIO-T3 across these categories and therefore agree that basing the assessment on a qualitative review of the engineering justification papers (EJPs) and evidence submitted is more appropriate than a quantitative assessment methodology relying on historical run rates.

In regard to non-operational property, we understand Ofgem's feedback on the two disallowed schemes and provide responses to these in our responses to NGETQ10. However, it is worth noting that the two EJPs for those schemes include the funding request for the essential ongoing asset health maintenance for the two sites – National Grid House (NGH) and Eakring – and therefore even in the absence of support for the schemes, our request for baseline funding should be considered and awarded prior to an in-period reopener. This is [REDACTED] for NGH and [REDACTED] for Eakring. For Eakring, we have revised our maintenance request and are also requesting preliminary funding to progress the scheme ahead of more detailed cost certainty (please see NGETQ10 for more information).

At Final Determination Ofgem should:

- **Maintain its current cost assessment approach for Vehicles and Transport and Non-operational property.**
- **Confirm baseline funding for the essential ongoing asset health maintenance at our National Grid House and Eakring non-operational property sites**

ETQ52. Do you agree with our assessment approach for IT&T? Do you think we should make any amendments to the assessment framework, or the thresholds employed? Should any cost categories be included or excluded from the assessment?

We do not agree with Ofgem's current IT&T assessment approach as it does not award efficient funding for projects which are deemed to be approved and needs case endorsed by that same assessment process. The approach mixes IT investments with ongoing operational costs (RtB), leading to insufficient funding. Ofgem's approach here differs from all other assessment approaches used across the plan, where an engineering assessment determines need and a separate cost assessment is undertaken, leading to inconsistent regulatory outcomes.

IT&T capabilities are critical enablers of the Digitalisation portfolio, which was strongly endorsed by Ofgem with 98% of our requested funding awarded. This approach risks systemic underfunding of foundational IT services, introduces regulatory uncertainty, and undermines the delivery of consumer value.

There are eight reasons we disagree with the approach and outcomes:

1. Conflating the needs case and efficiency assessments leads to underfunding of required investments.
2. The approach results in unjustified 'cliff-edge' effects in funding
3. The framework does not adequately assess 'end-of-life' investments
4. Linking the assessment of Investment and Run the Business costs conflates two inherently different types of costs
5. The framework is not appropriate for critical infrastructure systems that span RIIO-T2 and T3 (non-typical IT investments)
6. The Draft Determination contains errors
7. The lack of transparency in the approach limited our ability to provide the information that Ofgem needed
8. The lack of transparency in the result limited our ability to respond effectively to the Draft Determination

We have also responded to Ofgem's feedback regarding the categorisation of several projects and cost items between Data & Digitalisation, Cyber and IT & Telecoms. We include updated tables, highlighting where these changes are seen.

We propose a handful of pragmatic solutions, recognising the limited time available between Draft and Final Determinations and therefore focus on addressing the most significant weaknesses of the assessment approach.

In Final Determinations Ofgem should:

- Reinstating full funding for below £1m "Other IT" investments to be consistent both with RIIO-2 and across sectors in RIIO-3.
- Provide guidance to Networks on how scope reductions should be assessed and communicated with Ofgem for any investments that have allowances materially below requested funding.
- Revise the threshold model to introduce smaller (5%) funding steps between current anchors, reducing volatility and better aligning funding with assessment outcomes.
- Explicitly recognise 'end-of-life' investments as legitimate and necessary, with a default Green RAG for Value for Money where appropriate criteria are met.
- Undertake a separate assessment of the IT RTB costs, using a combined quantitative and qualitative review that considers the historic run rates, the identified changes and the benchmarking evidence provided.
- Apply tailored assessment criteria to SCADA and Optel investments, which are critical infrastructure projects requiring continuity across regulatory periods and limited in delivery optionality.
- Consider the additional evidence provided by NGET to support the investments and the information regarding the costs and projects moving between categories
- Correct the identified errors and share a single detailed model that covers the IT&T investments, making it clear what funding has been awarded.

Ofgem should also commit to supporting effective cross sector working groups and open consultation well in advance of developing an IT&T specific assessment approach for future price controls that appropriately considers the cost assessment of agreed projects.

1. Conflating the needs case and efficiency assessments leads to underfunding of required Investments

The assessment deviates materially from the RIIO-2 methodology by applying onerous funding penalties to investments of up to 75% disallowance for investments with a needs case supported by the assessment. This appears to be in lieu of a true assessment of efficient cost. This is both flawed as an approach due to the conflation of the needs case and cost assessment of an investment and is inconsistent with regulatory precedent, the assessment of other regulatory categories and across sectors.

Whilst the fundamentals of the RAG based assessment were first developed in RIIO-2, maximum disallowance was set at 25% of requested funding. Ofgem have provided no rationale or evidence for this change and no basis upon how it anticipates networks can deliver the outcomes of projects which are clearly supported with as little as 25% of requested funding.

Funding below 95% creates a situation where the only viable option is to reduce or remove scope. The first elements at risk are those that are more transformational in nature and offer the greatest long-term value to consumers, such as enhanced platform capabilities and resilience features. As funding drops further, particularly below 85%, networks face a scenario where even the delivery of current services becomes unsustainable. This would significantly accelerate the accumulation of technical debt and compromise system stability. Applying such reductions to projects with a clearly evidenced need undermines value for money, introduces false economies, and risks long-term inefficiencies.

These changes and the funding outcomes are notably inconsistent with the other elements of the Non-Operational Capex cost category. Across Digitalisation, Property and Fleet where Ofgem has supported the need for investment the requested funding has been accepted based on a detailed review of the evidence submitted in EJPs rather than the categorisation and formulaic approach taken for IT&T. The proposed funding reductions across these other areas have therefore explicitly reduced and removed scope where allowances are not awarded.

Further inconsistency appears between sectors and between regulatory categories regarding the proportionality of the assessment and the approach to assessment of lower value investments.

- In RIIO-3 Gas Distribution Draft Determinations, investments below £0.5m are fully funded with no assessment applied, consistent with the RIIO-2 approach.
- The approach taken to the Network Operating Costs (NOCs) quantitative and qualitative reviews sets a £1m threshold for detailed reviews, with line items below this awarded allowances in full.

The RIIO-T2 approach similarly fully funded investments below £1m, the de minimis level apparent in Ofgem's BPDTs. However, in T3, these lower materiality investments are not funded without assessment, nor are they assessed on their own merits, despite evidence having been provided that would support such an approach. Instead, investments below £1m are now subject to partial funding based on the average funding % across the portfolio. Ofgem has not provided rationale or evidence as to why this change has been made or why this is different across sectors.

Whilst the impact of this change for National Grid is around £3m, it further demonstrates that the changes made to the IT&T assessment approach have not been made with consideration to Ofgem's stated intention to simplify Cost Assessment. They further suggest an uneven application of assessment standards to similar investment categories, undermining the consistency, fairness, and credibility of the process and Ofgem must resolve this for Final Determinations.

We propose that in Final Determinations Ofgem should:

- **Reinstate the approach taken in RIIO-T2 of full funding for below £1m "Other IT" investments**
- **Provide guidance to Networks on how scope reductions should be assessed and communicated with Ofgem for any investments that have allowances materially below requested funding. This would ensure transparency and avoid disputes when Networks submit future need cases that would otherwise appear to duplicate those submitted in our initial RIIO-T3 business plan.**

In the longer term, consideration should be given to how a true assessment of cost efficiency could be undertaken for IT Investments, as is done across all other categories of spend and how. We hope to work with Ofgem well in advance of any T4 price control to support this.

2. The approach results in unjustified ‘cliff-edge’ effects in funding

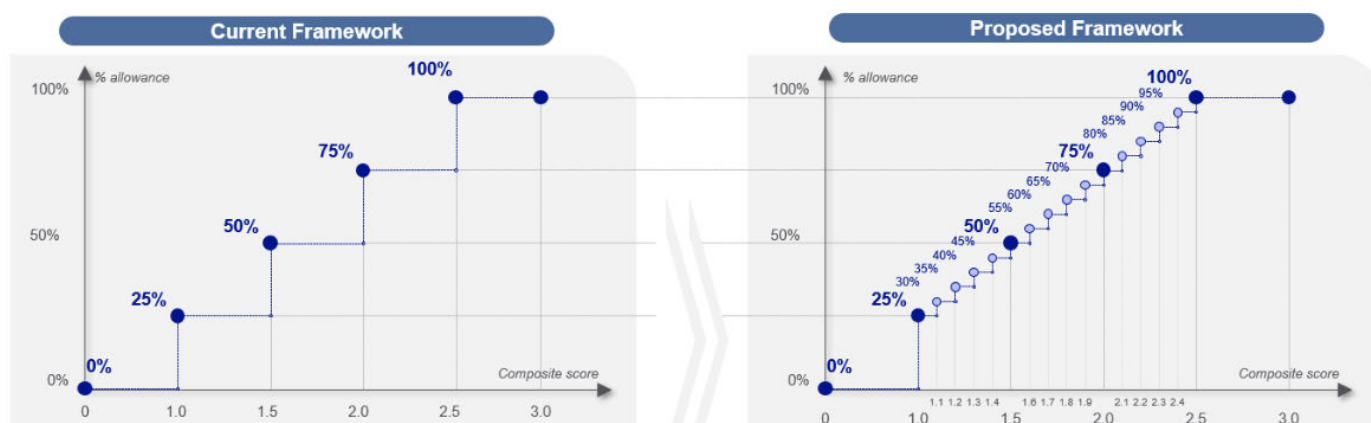
The current threshold model converts composite scores into funding outcomes using broad score bands with large step changes. Small changes in score can therefore result in abrupt and disproportionate shifts in funding, creating cliff-edge effects. For example, a marginally lower score can reduce funding by 25%–50%, even where the investment case remains strong.

This step-based approach risks underfunding efficient projects that deliver significant consumer benefit but fall just short of a threshold due to minor differences in scoring. It also reduces the incentive for incremental improvement, as small score increases may not translate into any additional funding. To address these concerns and support a more proportionate funding model, we propose revising the threshold model to eliminate large step changes and ensure funding is provided for all positive assessments.

In Final Determinations, Ofgem should introduce 5% step changes in the funding thresholds.

This would provide a smoother translation from score to funding, better reflecting the strength of individual investments, and improve the transparency and fairness of the outcome without overhauling the framework’s core logic.

Image 1. Current vs proposed framework



3. The framework does not adequately assess ‘end-of-life’ investments

The current scoring places significant weight on optioneering and cost-benefit analysis. While this is appropriate for discretionary or transformational investments, it fails to account for projects where assets are at the end of their maintainable life and where there is no credible “do nothing” option.

Such investments may not return a positive NPV because their purpose is to maintain operational continuity and manage risk, not to deliver quantifiable cost savings. Penalising these investments through the scoring system risks systemic underfunding of essential infrastructure and accelerates the accumulation of technical debt.

A clear example of this is the replacement of legacy Optel systems, which must be undertaken to maintain operational continuity and avoid unacceptable risk. While the risk of interruption to operational continuity may be low, the potential costs in terms of safety and consumer impacts are substantial. However, these risks and impacts are difficult to quantify in cost-benefit analysis.

End-of-life investments be clearly defined as those where the current asset has reached the end of its maintainable or supportable life, and continued operation would pose unacceptable risk or cost.

These cases typically do not return positive NPVs on a purely cost based assessment, not due to inefficiency, but because they are essential to maintain baseline service, manage operational and safety risks, and prevent costly future failures.

Where an investment is clearly classified as ‘end-of-life’ and qualitative evidence supplied as to the end-of-life risks, it is provided a Green RAG status for Value for Money by default.

This would prevent inappropriate penalisation of necessary replacement activity and ensure consistency in how these cases are assessed.

4. Linking the assessment of Investment and Run the Business costs conflates two inherently different types of cost

Ofgem's proposed approach to assessing the IT Run the Business (RTB) costs is flawed. The approach does not consider the forecast on its own merits and instead applies the percentage disallowance from the review of Investment projects to this RTB forecast. To note, these costs are split across both the Operational IT and Business Support Costs tables in the BPDs.

This method is incorrect because it implies a relationship between two fundamentally different types of spend, each driven by distinct factors and forecasted in different ways. IT RTB costs are necessary for the operation of existing IT systems and include, for example, existing contractual agreements in place with suppliers, providing internet services (Wifi) to our office locations and the IT service desk that supports our workforce. In the NGET business plan, this was forecasted by considering the current T2 run rates before overlaying known differences such as:

- Incremental RTB from the proposed Investments
- Identified efficiencies from our Project Apollo zero based budgeting review
- Incremental costs from the SCADA programme

This is further explained in our Cost and Benchmarking Annex submitted alongside the Business Plan (pgs. 36-40). Within this, we also explain how this forecast has been benchmarked against an external benchmark provided by McKinsey & Company, placing our forecast in the upper quartile for the comparator group. However, the current assessment approach ignores this evidence and gives no consideration to the prior run rates of spend, instead applying a disallowance based on an assessment of unconnected investment projects.

Ofgem should instead undertake separate assessments of IT RTB costs, considering both the quantitative and qualitative evidence provided by networks.

A purely quantitative based assessment would not be appropriate for these types of costs as generally results in a backward-looking view of cost efficiency and does not consider:

1. Identified one-off items that would need to be separately considered
2. Increasing levels of IT investment and automation where increasing IT spend is more than offset by benefits and cost reductions in other categories of spend

Conversely, a qualitative assessment would require a significant amount of work for both networks to develop the detailed evidence and for Ofgem to undertake such detailed assessments.

Therefore, in Final Determinations, Ofgem should undertake a combined quantitative assessment for IT RTB costs identified on the Business Support and Operational Technology tables (removing Project Opex costs that are assessed as part of the investments) separate from the investment projects assessment. This assessment should consider the historic spend run rates and then supplement with a qualitative review of evidence provided by networks, where costs or forecasts have changed as well as benchmarking to external comparators. This proposed approach is aligned to the approach for Indirect spend where the statistical modelling approach is supported by separate assessments of items for which the modelling does not adequately consider.

5. The framework is not appropriate for critical infrastructure systems that span RIIO-T2 and T3 (non-typical IT investments)

SCADA and Optel are not typical IT projects; they are critical infrastructure systems that span RIIO-T2 and T3 and play a foundational role in network operation. Given their strategic importance and limited delivery flexibility, the standard IT&T assessment framework is not well suited to evaluating them.

NGET's SCADA and Optel investments should be assessed separately using tailored criteria.

Assessment through the proposed IT&T approach fails to recognise previous Need Case and Funding decisions taken by Ofgem throughout RIIO-T2.

- For Optel the Need Case and requirement to invest was fully supported in the RIIO-T2 Final Determination. Scope and allowances reductions were made to reflect what Ofgem believed was the appropriate pace of delivery. This moved approximately half of the investment into the RIIO-T3 period. The submission we made in our RIIO-T3 business plan is for that half of investment deferred by Ofgem.
- For SCADA it gives no consideration to the standalone re-opener that Ofgem and National Grid undertook together during RIIO-T2. This included Need Case and Project Assessment phases meeting all the content and quality requirements as set out in Ofgem's Reopener Submission Guidance.

As such, for Final Determinations, these projects should be considered outside of the standard IT&T assessment, ensuring that this context and the previous decisions are appropriately considered. However, whilst we believe this strongly, the operational risk of underfunding these investments is significant and so we are also providing additional supporting evidence (Addendum 6 and Addendum 7) with the intention of allowing improved RAG scoring within the current IT&T assessment. We are taking this dual approach to our response to SCADA and Optel specifically because the impacts of underfunding these investments is so material to our core Business operations and the obligations placed upon us as a Transmission Owner.

6. The Draft Determination contains errors

There are several technical errors in the Draft Determinations that materially impact funding decisions:

- For 3 investments within “Procurement: Source to Pay” EJP (PRJ-6897, PRJ-6898, PRJ-6900), the calculated composite score returns as 2.0, which should correspond to a 75% funding level under Ofgem’s published framework. However, the outcome is hardcoded in the assessment Excel and indicates only a 50% funding, contradicting the stated methodology.
 - PRJ-6897: [Value for Money - Red] 1 x 20% + [Optioneering - Amber] 2 x 20% + [Scope - Green] 3 x 20% + [Certainty - Amber] 2 x 20% + [Assurity - Amber] 2 x 20% = 0.2 + 0.4 + 0.6 + 0.4 + 0.4 = 2.0 à 75%
 - PRJ-6898: [Value for Money - Red] 1 x 20% + [Optioneering - Amber] 2 x 20% + [Scope - Green] 3 x 20% + [Certainty - Amber] 2 x 20% + [Assurity - Amber] 2 x 20% = 0.2 + 0.4 + 0.6 + 0.4 + 0.4 = 2.0 à 75%
 - PRJ-6900: [Value for Money - Red] 1 x 20% + [Optioneering - Amber] 2 x 20% + [Scope - Green] 3 x 20% + [Certainty - Amber] 2 x 20% + [Assurity - Amber] 2 x 20% = 0.2 + 0.4 + 0.6 + 0.4 + 0.4 = 2.0 à 75%
- Within the ITT_Draft final report the investment under PRJ-8101 has been incorrectly categorised as an Optel project “Generation 3 Refresh (Inc Control Telephony)”. This investment relates to a distinct project within the digitalisation portfolio – “IoT platforms and sensors” within “Operational Management” EJP and should not have been subject to the specific treatment applied to telecoms infrastructure.
- There are errors in the Draft Determinations models related to the treatment of the SCADA programme. The project has been removed through the normalisation adjustments; however, the disallowance related to the project assessment has then been further removed, leading to a negative funding position for the project. This was raised in DDQ032, and we expect will be resolved for Final Determinations.

These errors not only lead to unjustified disallowances but also highlight the need for greater transparency and quality assurance in the application of the assessment framework. Furthermore, Ofgem have shared several different sets of data regarding the project-by-project split of funding (between the “ITT_draft final report_NGET” pdf, NOC & Non-Ops Capex models and the response to DDQ NGET015) which do not entirely align. This has made it hard to trace and understand the allowances awarded and therefore understand what outputs have been supported for delivery.

In the Final Determinations, Ofgem should correct the identified errors and share a single, quality assured, detailed model that covers the IT&T investments, making it clear what funding has been awarded for each of the projects, to ensure TOs have clarity as to the funding decisions.

7. The lack of transparency in the approach limited our ability to provide the information that Ofgem needed

The assessment approach was not shared or discussed with TOs prior to Draft Determinations – including in the Sector Specific Methodology Consultation (SSMC), at Cost Assessment Working Groups or in Business Plan Guidance (BPG). Whilst brief reference to continuing with the RIIO-2 approach were made material changes have been made with no stakeholder engagement or impact testing.

Due to this lack of information, we engaged with Ofgem on several occasions prior to Business Plan submission about the appropriate IDP templating to use for IT&T investments, given that those provided did not align well with the known RIIO-2 assessment approach. We were told to follow the typical EJP guidance, limiting our ability to provide elements of evidence and detail that now appear to have been beneficial to the assessment of IT&T investments.

Now that we have been provided some detail of the categories, criteria and scoring thresholds used in the assessment, we understand the evidence that would have strengthened assessed categories. Particularly around optioneering, delivery certainty and cost assurance. We are providing this now via addendums targeted at those investments with an assessment that did not result in 100% funding outcome²¹.

²¹ Addendum 1: ERP Systems; Addendum 2: Procurement Source to Pay; Addendum 3: DPIT Delivery; Addendum 4: DPIT Infrastructure; Addendum 5: DPIT Platform; Addendum 6: Optel; Addendum 7: SCADA;

8. The lack of transparency in the result limited our ability to respond effectively to the Draft Determination

We are providing additional evidence with only a limited understanding of the perceived concerns about our proposed investments, having received no specific explanation beyond the simple RAG status. This contrasts with the approach taken for all other proposed investments in the plan for which the company specific annexes contain useful commentary about Ofgem's concerns, therefore supporting networks to appropriately address these ahead of Final Determinations. This lack of transparency does not support an effective framework or cost assessment approach and must be corrected.

We also bring to Ofgem's attention that section 1.1 of all BAU IT Capex EJPs referred to independent benchmarking activity undertaken by Gartner. We engaged Gartner between June and August 2024, giving them access to draft versions of our IDPs and facilitating working sessions between them and relevant NGET SMEs. This allowed Gartner to compare our planned investments against relevant peer organisations and projects. This benchmarked the Project Totex (excluding RtB) of the BAU IT Capex investments at the Portfolio IDP level.

Along with relevant Addendums we believe this benchmarking allows cost assurity to be assessed as Green. For convenience a summary of the benchmark outcomes for the investments that Ofgem have assessed is shown below.

<i>EJP</i>	<i>Gartner Assessment</i>
DPIT – Delivery	In Range
DPIT – Digital Workplace	In Range
DPIT – Infrastructure	In Range
DPIT – Platform	In Range
ERP Systems	Below
Procurement Source to Pay	In Range

Ofgem should consider this evidence as part of the Final Determinations and appropriately share concerns regarding the proposed investments. We welcome Ofgem's confirmation that they will continue to work with networks through September to facilitate this.

Recategorisation across tables

Reflecting Ofgem's feedback, some changes that are required to NGETs submitted tables as to the categorisation across different parts of the submission. Alongside this response we provide updated tables and information for the following:

- The costs and an EJP related to the Core 2 project that was submitted in our Business Plan as part of the Cyber submission. This is in line with Ofgem's feedback in Draft Determinations to resubmit this project as part of the non-operational capex assessment.²²
- The Site Comms investment (PRJ-8098) was included on the Data & Digitalisation table, but Ofgem have suggested that it is more suited to the IT&T investments (NGET annex paragraph 7.8). This appears to have been assessed in the IT&T assessment (as per the "ITT draft final report NGET" pdf but does not appear in the awarded allowances. This is now included in the table submitted alongside this response.
- We now understand that the incremental RTB costs associated with the Data & Digitalisation investments should have been included on the D&D Memo table alongside the capex costs of the investments, with these only included in RTB in the following price control.

²² The EJP associated with this investment has been submitted in the Cyber Draft Determinations response (via SIE link)

ETQ53. Do you agree with our quantitative assessment approach, ie unit cost and annual average costs using RIIO-ET2 and RIIO-ET3 data? If not, how should we carry out the quantitative assessment?

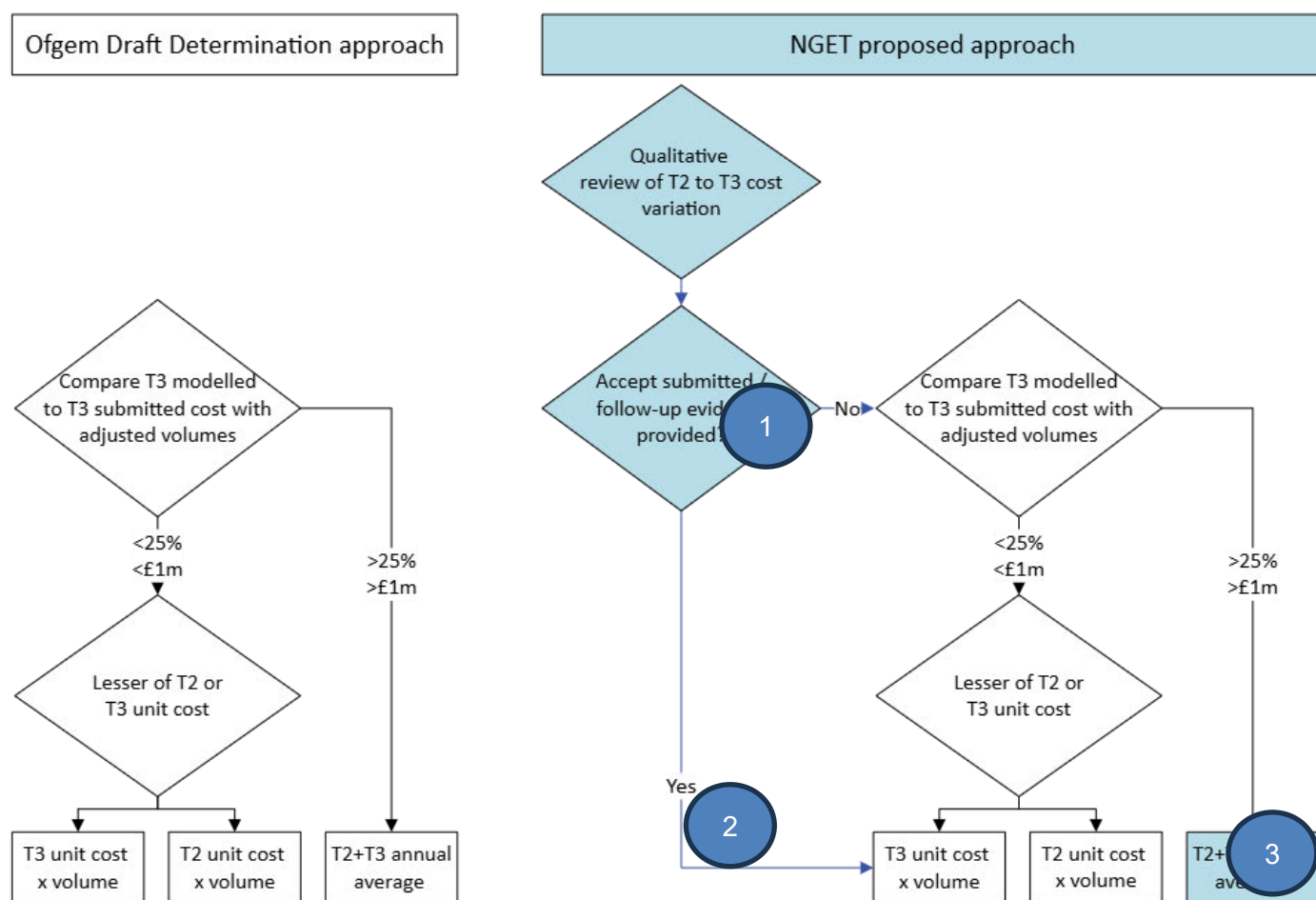
We do not agree with the current approach to assessing NOCs. We are supportive of a quantitative approach to NOCs where possible, but we do not agree that the current approach appropriately accounts for the step change seen in some NOC categories, with the use of an annual average calculation undermining the recognition of a step change. We view that an improved approach would be to adopt a combined quantitative and qualitative methodology, making full use of the evidence provided by TOs to consider volume changes.

In the approach outlined in Draft Determinations, Ofgem undertakes a modelling assessment of all NOC lines that are identified for quantitative assessment. This involves calculating a modelled allowance based on the lower of T2 or T3 unit costs. This is followed by a step change review, where if the modelled allowance has a variance of more than £1m or 25% compared to the submitted request, the calculation is updated to take an annual average approach. This is shown on the left-hand side of Figure 18.

There are three key issues with this approach that must be resolved:

1. A step change check occurs only after the quantitative modelling stage.
2. Where Ofgem's approach recognises step changes in unit costs an annual average across T2 and T3 is applied, which results in understated T3 unit costs and unfairly reduced allowances. TO evidence should be considered.
3. The annual average is incorrectly calculated and conflates unit costs and volume changes between the two periods. This methodology must be updated and corrected.

Figure 18: Left: Ofgem Draft Determination approach; Right: NGET proposed process, adjustments highlighted in blue. The numbers align to the numbers in the bullet points above



1: Step change check to identify whether quantitative or qualitative assessment is most appropriate

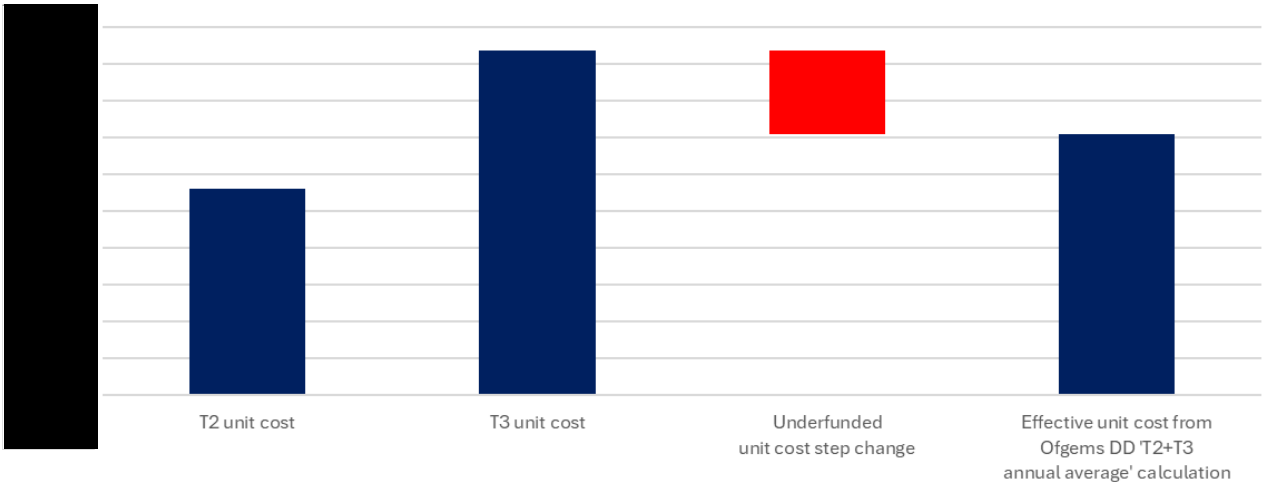
In the Draft Determinations, Ofgem recognised that there has been a significant step change in the unit costs and/or volumes of some areas which the T2 approach would not account for. However, the proposed solution does not appropriately identify or address the step change issue. Specifically, the approach conflates the step changes caused by volumes and unit costs, and ignores any evidence supplied by TOs to support these changes.

Ofgem should introduce an additional step change check prior to the quantitative assessment. The new step should identify NOC line items where there has been a significant change in either the volumes or unit costs between periods. It should also consider where TOs have provided evidence to support the requested allowances. This step would trigger an additional qualitative review prior to the quantitative calculation of allowances. We explain our proposed approach for this in ETQ54.

2: Use of T3 unit costs where step change evidence is provided and supported

Ofgem’s proposed approach recognises some line items where there has been a step change in unit costs. However, where this is recognised, the proposed solution is to award allowances based on the T2+T3 annual average cost across the T3 period. The result is that unit costs for the T3 period will be understated and allowances unfairly reduced.

Figure 19: Example of T2 to T3 unit cost step change for Repairs - Substations - Auxiliary Systems

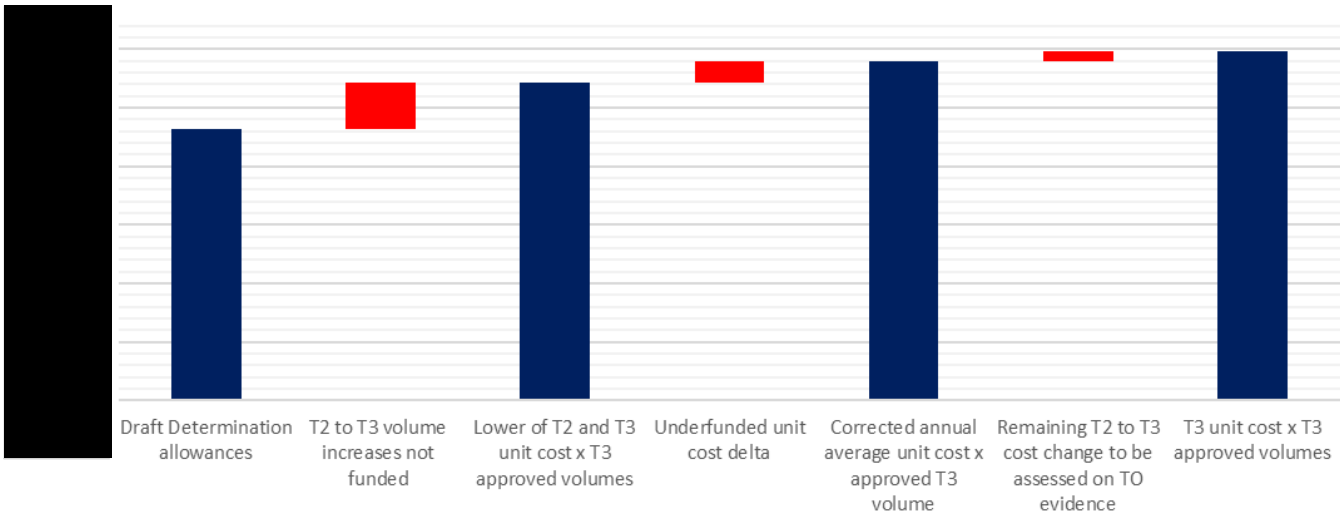


Instead, Ofgem should give regard to the evidence that is provided by the TOs. Where evidence of a step change of unit costs is reviewed and supported, Ofgem should calculate the allowances using the T3 unit costs rather than the annual average.

3: Calculation of the annual average is incorrect

Ofgem performed an engineering review that considers and assesses volume changes between T2 and T3. However, the T2+T3 annual average is calculated by taking the sum of 10 years of total costs over T2 and T3 periods, and divides by 10. Considering the total cost rather than annual unit cost means the volume driven changes between T2 and T3 are not accounted for. As a result, the unit cost generated ignores this approved increase in volumes and is set incorrectly low, resulting in an incorrectly reduced allowance.

Figure 20: Example of annual average calculation underfunding for Maintenance – Substation – Protection and Control



In Figure 20, we illustrate that the Draft Determination allowances are below the minimum allowances generated when applying the lower of T2 and T3 unit cost multiplied by approved T3 volumes. The first red bar shows that this NOC line

is underfunded by [REDACTED] due to the cost calculation not accurately accounting for volume changes between T2 and T3 when using the lowest available unit cost.

The second red bar within Figure 20 illustrates there is additional underfunding because the annual average cost does not represent a true annual average unit cost over the 10 years of data available to Ofgem. This equates to [REDACTED] of this NOC line.

The third red bar is not applicable to this 'Calculation of the annual average is incorrect' section, but is the remaining disallowance should Ofgem have reviewed the evidence submitted by the TO and agreed to approve the T3 unit cost, which links to point 1 of ETQ53 and explained in detail in ETQ54.

Recommendation

To resolve this, Ofgem should change the T2+T3 annual average calculation. It should calculate the average of the annual unit costs from each of the ten years in the T2 and T3 periods, to calculate a true annual average unit cost. This can then be multiplied by the approved T3 volumes to calculate the final allowances.

Without these adjustments, the current methodology is too heavily weighted on the T2 unit costs. This is despite recognition by Ofgem of the high volatility and increase in costs between the T2 and T3 periods and therefore would lead to the systematic underfunding of TOs. Ofgem accepts this point on other cost areas within the submission (e.g. para 5.26 where Ofgem specifically rejects its previous methodology of choosing the lower of the benchmarks between T2 and T3). Whilst cross-TO benchmarking would remove the reliance on T2 costs as a reference point, we do not believe that this alternative is appropriate for NOCs in their current form. This is due to the clear reporting differences between the TOs. Therefore, we understand the need for the T2 unit costs to form part of the benchmark but urge Ofgem to apply our additional checks for step changes and appropriately weight the T3 unit costs where these checks indicate that a change has occurred between periods. Addressing these points will enable a fair and robust NOC quantitative assessment.

In addition to the above points, there are calculation errors in the modelling that need to be resolved ahead of the Final Determinations. We have identified these through the Ofgem Gitlab process. An extract of this is included in Annex NGET_RII03_ETQ47_Model and formula errors.

By Final Determinations, Ofgem should:

- **add a further step change check to the cost assessment process that appropriately considers the qualitative evidence provided by TOs and removes the systematic reliance on T2 unit costs where they are proved to no longer be relevant or appropriate.**
- **correct the calculation of the annual average to calculate a true annual average unit cost and distill the impact of volume changes. This is in addition to correcting the formula errors identified in the modelling and communicated through Gitlab.**

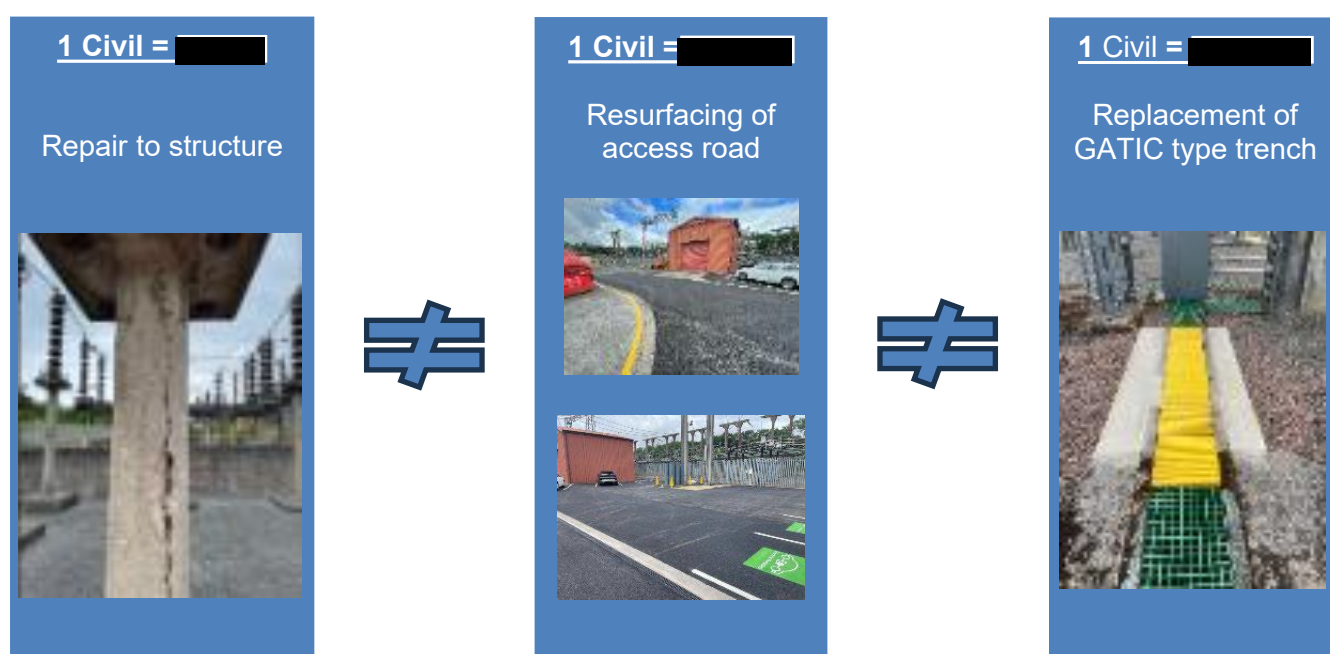
ETQ54. Are there any NOCs categories or sub-categories that we should have excluded or included from quantitative assessment? If excluded, how should we assess them?

Yes, there are some additional NOC categories and sub-categories that should have been excluded from the quantitative assessment.

The civils costs should be permanently excluded from quantitative analysis and instead be assessed through qualitative methods. In addition, through enacting our proposed step change check mentioned in ETQ53, additional sub-categories are identified which would justify a qualitative step introduced to the quantitative review.

Exclusion 1: Civils

Civils by their nature have no single defined unit and are therefore unsuitable for standard quantitative unit cost benchmarking. It is not appropriate to apply unit cost benchmarking to Civils as a category since it is not possible to define one 'unit' of civils from which a meaningful benchmark can be formed. To demonstrate this, below are three civils activities that would be attributed to "1" volume as per the RIGS, highlighting that civils is not benchmarkable due to significant range in scope:



For Load and Non-Load capex, Ofgem comment within ET Annex 5.25 that it is not feasible to benchmark some costs. We can subsequently identify that all civils costs within the Load and Non-Load capex model were excluded from any benchmarking; likely for this reason. We believe civils as a cost category faces the same benchmarking challenges within NOCs as it does for Load and Non-Load capex, so the cost assessment methodology should be mirrored.

Further evidence and commentary have been provided in NGETQ10 regarding the engineering and qualitative assessment of civils.

In Final Determinations, Ofgem should undertake a qualitative review of our submission for civils, replacing the current quantitative unit cost benchmarking methodology applied.

Exclusion 2: Material rows where qualitative evidence has been provided

As mentioned in ETQ53, the quantitative assessment would be more robust should Ofgem introduce a new initial "step change check" prior to the quantitative review and incorporate qualitative evidence when it has been provided. This would enable consideration of TOs evidence and justification for instances of a step change in unit costs between T2 and T3, rather than rely on the T2+T3 annual average as the default solution. We have identified two solutions and prefer Option 1:

- **Option 1 - Logical check for qualitative evidence:** At the start of the assessment criteria, Ofgem should consider all submitted qualitative evidence for the unit costs provided by TOs. If the evidence provided is robust in Ofgem's view, then this should be the primary source for cost assessment, taking precedence over

the other benchmarking assessment outcome. Where the cost evidence submitted is agreed by Ofgem, then the T3 unit cost should be applied in the NOCs model. In practice, TOs are likely to only provide detailed qualitative evidence where a significant step change exists. It is therefore unlikely to significantly increase the number of lines to which this qualitative data step would apply compared to the more mechanistic second option outlined next.

- **Option 2 – Step change check to unit costs:** Performing an automatic statistical check would help Ofgem identify where there may be unit cost volatility between T2 and T3. Where present, it should initiate a review considering whether qualitative evidence has been submitted by TOs. For each NOC row being quantitatively assessed, we propose the following calculation is performed initially to identify if there has been a step change in costs between T2 and T3:

$$(T3 - T2 \text{ mean unit cost}) \times T3 \text{ volumes}$$

Through applying this formula within the NGET NOCs model for T3 Draft Determinations, this would have identified 13 NOC rows with a step change greater than £1m, which we recommend would warrant review of any qualitative evidence provided. We judge this as a manageable threshold where Ofgem can intervene and scrutinise the evidence presented within IDPs. In doing so, Ofgem will better balance the need to protect consumers from overpaying where submitted costs are not considered justified, with providing suitable funding where specific NOC costs can transparently be shown to have increased yet remain efficient. This amended approach has identified eleven NGET NOC rows for an initial qualitative assessment as detailed in Table 1, where two NOC costs are already captured by Exclusion 1 civils.

Table 1: Table of NOC Lines triggering the proposed £1m threshold for qualitative check for which NGET has provided qualitative evidence:

BPDT Totex OAP ID	Table	Asset Heading / Category	Asset Sub-Category	Evidence for consideration
NO033	8.3 Maintenance	Assets / Substations	AIS	Detailed later in this ETQ54 response
NO036	8.3 Maintenance	Assets / Substations	Protection and Control	BPDT Commentary pg. 94
NO037	8.3 Maintenance	Assets / Substations	Auxiliary Systems	NGET084
NO054	8.4 Repairs	Assets / Substations	AIS	A056 - Substation Minor Capex and Repairs
NO057	8.4 Repairs	Assets / Substations	Protection and Control	A056 - Substation Minor Capex and Repairs
NO058	8.4 Repairs	Assets / Substations	Auxiliary Systems	AO52- Substation Battery Systems and Room Upgrades; AO53 - Substation LVAC Auxiliary Infrastructure, NGET084
NO069	8.4 Repairs	Assets / Cables	400	AO42- Cable Repairs and Minor Replacements
NO079	8.6 Veg Management	Kilometers Cut	400kV	BPDT commentary pg. 100
NO088	8.7 NOCs other	Earthing upgrade by number of locations		A056 - Substation Minor Capex and Repairs, NGET084

Would be included in Table 1 but duplicated by Exclusion 1 civils:

NO038	8.3 Maintenance	Assets / Substations	Civils	NGET084
NO059	8.4 Repairs	Assets / Substations	Civils	AO34- Substation Infrastructure Civils; AO56 - Substation Minor Capex and Repairs

Where Ofgem is unconvinced with the qualitative evidence, we would welcome the opportunity to receive this feedback (as is done for engineering assessments) enabling TOs to provide additional evidence and clarity. We understand Ofgem may execute regulatory judgement should the required evidence have been omitted, instead choosing to proceed with the remaining quantitative process steps.

In Final Determinations, Ofgem should update their wider NOCs assessment approach to ensure that evidence regarding line items that have a material change between T2 and T3 is appropriately considered before defaulting to a quantitative review.

Further information as per Table 1 above:

Maintenance: AIS

Unit costs for this activity are increasing as evidenced in our RRP submissions. Therefore, the average unit costs for the T2 period are not reflective of the future expected costs. Weight should either be given to only the latter years of T2 or the T3 period only.

Table 2: RRP25 extract for Maintenance AIS

	2022	2023	2024	2025	2026	T2 Unit cost as per BPDT	T2 unit cost as per RRP25	T3 unit cost as per BPDT
Costs								
Volumes								
Unit Cost								

ETQ55. Do you consider that the 25% and £1m thresholds are appropriate for the quantitative assessment of NOCs? If not, what should the thresholds be and why?

We agree with the introduction of the thresholds to recognise the step change between T2 and T3 and are comfortable with the proposed values of 25% and £1m.

However, Ofgem should refer to our response to ETQ53 and ETQ54 regarding the introduction of an additional step change check based on preferably the provision of qualitative evidence by the TOs, or alternatively a step change in unit cost value between T2 and T3 which drives a variance greater than £1m.

Ofgem should maintain its position with regards to values of thresholds for Final Determinations. However, Ofgem should implement an additional check and threshold on unit costs specifically to ensure that the calculation of allowances appropriately recognizes the changes and volatility in costs between the T2 and T3 periods.

ETQ56. Do you support our qualitative assessment framework for NOCs other (Vegetation Management, Ongoing environmental costs, Small Tools Equipment Plants & Machinery (STEPM) and company bespoke NOCs other costs) and Flood Mitigation? If not, how should we assess these costs? Are there any additional costs that we should include in this framework?

We agree with Ofgem's qualitative assessment framework for the scope mentioned in this question and agree the materiality threshold to focus on the higher value rows is in the consumer interest.

However, ahead of the Final Determinations, Ofgem must:

1. Consider the additional evidence in support of our investments and spend

We understand Ofgem's feedback regarding some investments and have provided detailed responses to these in our NGETQ10 response. Specifically these are:

- Operational Estate Investment
- Energy Efficiency
- Fixed Wire Testing
- Sub-metering

2. Reassess Service Agreements

Also included in NGETQ10 is our response regarding Service Agreements. Whilst this is not included within this qualitative assessment, as outlined by Ofgem, we recognise Ofgem's feedback in ET Annex paragraph 5.81 and are addressing this in our response. Ofgem must assess this additional evidence when revising the cost assessment for Final Determinations.

Ofgem should maintain its position at Final Determination for the scope mentioned.

ETQ57. What are your views on the proposed blended approach to CAI? Do you agree with the weights applied?

We do not agree with the approach to CAI in the Draft Determinations. The errors and issues we discuss in response to this question are wider than just the blended approach and the weights applied, but are important issues which need to be resolved and this is the most relevant question in the consultation to include this information.

Ofgem must:

- **provide clear and detailed guidance that supports TOs to provide data on a consistent basis;**
- **correct errors arising from scope issues that mean funding for efficient and necessary costs is missing from the DD allowances; and**
- **consult on any revised or updated modelling approach.**

Our specific issues are summarised as follows:

- appears to be we understand this
- This inconsistency stems from ambiguity in Ofgem's Business Plan Guidance, and items left open to interpretation and uncertainty through the Cost Assessment Working Group process. This has led to a disconnect between how the three TOs have allocated indirects between pipeline and baseline spend. These inconsistencies are likely to undermine the validity of the modelling Ofgem undertakes and impact the assessment of both the baseline and pipeline funding requests.

Ofgem must actively work with TOs to resolve the data inconsistencies ahead of the Final Determinations, and ensure the TOs are given sufficient opportunity to be consulted properly on any revised modelling approach and results.

- **Missing funding.** Due to the complexity of funding arrangements within the price control, Ofgem must make a number of 'scope' adjustments to CAIs prior to benchmarking, with the aim of making like-for-like comparisons and avoiding double-funding of any costs. Ofgem's process for doing this in the Draft Determination, however, has meant that a number of material elements of our expected spend have not received determination or allowance (either in RIIO-3 or elsewhere). The specific issues are summarised below.
 - **ASTI projects – indirect overheads:** [REDACTED] of indirect overheads associated with the three ASTI baseline projects (and a further [REDACTED] which is directly associated with remaining 14 ASTI projects to be delivered in RIIO-3) is not provided in either the ASTI regime or RIIO-3 funding. Ofgem removed these costs from ASTI assessments for review at a later date, but has omitted the same costs from its RIIO-3 assessment. This means these costs are neither assessed nor allowed across either of the two funding routes. To correct this error, NGET's preference is for these costs to be considered as part of the ASTI regime rather than within T3 funding. However, Ofgem must confirm the planned treatment of these costs prior to Final Determinations to ensure completeness of funding.
 - **PCF indirects:** We agree with Ofgem's proposal to assess these separately. However, these costs have not been correctly added back to NGET's Totex allowances in Draft Determinations as a post-modelling adjustment. This means a further c. £50m of T3 funding has been missed.
 - **T2/T3 crossover indirects:** In general, Ofgem has excluded T2/T3 crossover projects from its Draft Determinations assessment. This leaves c. £300m of indirect costs with no route for funding in either T2 or T3 mechanisms (specifically, indirects for the projects badged "T2 crossover – assessment on T3 spend"). Ofgem must engage on the topic of T2/T3 crossover prior to Final Determinations to ensure this funding gap is addressed for the Final Determination. We also note that the exclusion of these projects has the potential to distort and undermine the CAI regression.
 - **T3 UIOLI (baseline) projects:** Ofgem has made determinations on the direct costs associated with these schemes, but has not assessed or allowed the indirect costs associated with these projects, causing a further funding gap of c. [REDACTED].
 - **Opex CAI:** Ofgem has removed £100m Opex CAI from our forecast prior to benchmarking, which Ofgem describes as a normalisation. We understand this was done on the assumption that these costs

would vary in proportion to the capex CAI items that have been removed. Ofgem's assumption is flawed and incorrect – these costs are mostly fixed. Funding for this necessary and efficient cost has therefore been missed.

- **Incremental ETCC running costs opex:** Ofgem has excluded [REDACTED] of incremental costs associated with the running of second control room and new SCADA system which have arisen as a result of the NESO separation. However, it appears that instead of applying separate assessment (as we assume was intended), the Draft Determination has simply removed this necessary funding entirely.
- **Modelling approach.** In light of the material data inconsistencies and missing funding issues described above, it is not possible meaningfully to assess the validity and robustness of the DD modelling approach. As it stands there are errors and flaws in the models that Ofgem has used. Ofgem's ratio analysis produces counter-intuitive results whereby the Scottish TOs receive higher allowances despite having lower drivers. The historical regression analysis implies modelled allowances for NGET which are significantly above our requested costs, raising questions about the model robustness. Once the data issues are resolved, Ofgem must issue revised models to the TOs for consultation on the modelling approach ahead of the Final Determination.

Data Inconsistency

One of the core issues across both CAI and BSC (indirects) is the consistency of data provided by the TOs and the lack of clarity in either the Business Plan Guidance or through the discussions with Ofgem that led to it. This issue was raised by the TOs in Cost Assessment Working Groups prior to the Business Plan submission. Whilst Ofgem requested the "baseline" data be resubmitted to drive to consistent data – in an SQ in March 2025 (NGET171) – limited additional guidance was provided to TOs at the time, resulting in continued differences in assumptions between TOs.

We remain concerned that the Cost Assessment Working Group process has not resolved these issues and note that many of the concerns discussed below arise from these consistency issues in the data, undermining the validity of the modelling Ofgem undertakes.

During the Draft Determinations consultation, Ofgem has issued a further SQ (NGET201), asking TOs to provide a further view of the "baseline" position in an attempt to derive a consistent view. Our response to this SQ has been submitted alongside this consultation response and we will cross-reference it throughout our response to these questions. We are expecting to receive a further SQ requesting the same information for the "Best View" position which will be essential to support Ofgem's new cost assessment approach.

The rest of our response to this question is split into the following sections, which align with Ofgem's sections in the ET Annex, and detail our concerns with the proposed approach and our proposed solutions:

- Scope of costs considered in the assessment
- The modelling approach
- Disaggregation of CAI costs
- Treatment of Contractor indirect costs

Scope of CAI assessment

Prior to undertaking the modelling, Ofgem has removed a significant portion of our baseline request from the assessment as part of the normalisation and exclusion adjustments. Whilst we understand and agree on some items, for many of the items this approach means that it is unclear how these costs will be assessed and efficient spend provided for. The absence of this clarity has left us unable to fully assess the implications of the Draft Determinations and therefore limits our ability to respond.

The following table shows each of the excluded categories, the Ofgem position, the issues with the position and our proposed solution:

Project Flag Category	
ASTI	<p><u>Ofgem Position at DD: Removed entirely from both the costs and drivers in the modelling.</u> In our Business Plan submission, NGET included three ASTI schemes that had undergone Project Assessment. Table 9.4 (CAI) of the BPDts includes both the indirect costs that are funded by these assessments and the indirect overhead costs that were removed from the assessments at the time. In response to SQ NGET171, we removed these costs from our “baseline” forecast at Ofgem’s request, but highlighted concerns about how the unfunded overhead costs would be considered and assessed.</p> <p>In the Draft Determinations, Ofgem excluded all ASTI data from the modelling, including both funded and unfunded indirect costs, project costs (from the capex driver), and ASTI assets (from the MEAV calculation). We understand this decision was intended to avoid duplicate funding for ASTI projects.</p> <p><u>Issues with Ofgem’s Position</u></p> <p>We agree that a significant portion of this spend is already covered by ASTI project assessments. However, Ofgem has given no indication in the Draft Determinations as to how the indirects overhead portion of these costs will be considered or assessed.</p> <p>The ASTI overhead indirect costs have not yet been assessed for funding under the ASTI regime, as they were previously excluded from project assessment decisions by mutual agreement. For example, in the EGL1 Project Assessment decision, it was stated:</p> <p><i>“We proposed not to allow [REDACTED] of funding requested for the NGET Strategic Investment element. We have agreed with the JV that the efficiencies and costs associated with implementing an ASTI programme, as well as the optimal method for funding such a programme, needed to be explored further.”²³</i></p> <p>In aggregate to the end of the T3 period, this equates to [REDACTED] for the three ASTI projects included in baseline; and a further [REDACTED] be delivered by NGET that are reported in the pipeline. It appears that Ofgem’s concern over duplicated funding has instead resulted in a gap in funding, where these costs are considered neither in the RIIO-T3 mechanisms nor via ASTI project assessments. This error must be corrected ahead of the Final Determinations.</p>
	<p><u>NGET Proposed Solution: ASTI Overhead funding provided as part of ASTI framework</u> Following discussions in bilateral meetings, in June 2025 we shared with Ofgem our proposal for the assessment of ASTI overheads, alongside a detailed cost forecast. We continue to believe that these costs are best excluded from the scope of RIIO-T3 and assessed once, as part of the ASTI regime, as a single overhead which is then applied to all 17 ASTI schemes.</p> <p>These costs are demonstrably associated with the ASTI schemes and therefore we believe it is appropriate that these are reported and funded as such, to avoid unduly understating the cost to deliver this work. Further, a number of complications arise should these costs be included within the T3 funding, including:</p> <ul style="list-style-type: none"> • Ofgem’s current modelling excludes ASTI costs and drivers (Capex and MEAV). If ASTI overhead costs are included, the drivers would need to be updated, risking duplicate funding for indirect costs already covered by project assessments. • There are complications regarding the funding of overheads for the 14 schemes that have not yet undergone Project Assessment (those in NGET’s pipeline). Since these schemes exceed the [REDACTED] threshold set by Ofgem, they would be assessed via Project Assessment, from which the indirect costs are currently excluded. This would result in inconsistent reporting of projects (with and without overhead) based on their status at the time of Business Plan submission, which is inappropriate. <p>Therefore, we agree it is correct to exclude the ASTI CAI and Capex from the CAI modelling. However, ahead of the Final Determinations, we require the certainty from Ofgem that these costs will be considered via the ASTI regime and should not be included in our T3 funding request. Should this proposal not be accepted, and instead these costs be included in the scope of the T3 funding request, Ofgem must provide clear direction on how these costs should be considered between “baseline” and “best view” and NGET must be given the opportunity to update the forecasts accordingly.</p>
Pre-construction Funding (PCF)	<p><u>Ofgem position at DD: Separately assessed outside of the modelling approach</u> Ofgem has chosen to consider PCF separately from the statistical modelling undertaken. To support this approach, in response to NGET171, at Ofgem’s request, the PCF values were removed from the submitted baseline.</p>

²³ Eastern Green Link 1 Project Assessment Decision (15th November 2024) <https://www.ofgem.gov.uk/decision/eastern-green-link-1-project-assessment>

	<p>EJPs associated with projects are then assessed and PCF awarded in line with the Ofgem policy. Please see response to ETQ26 above for our comments on this proposed policy.</p> <p>The agreed PCF funding should then be added back to the CAI allowances as a post-modelling adjustment.</p> <p><u>Issues with Ofgem's position</u> We agree this is the correct way to treat PCF. If not excluded, PCF requests would not be accounted for in the modelling as there is no equivalent driver data (i.e. capex cost of delivering the project is in the pipeline, not the baseline) included within the regression methodology.</p> <p>The post-modelling adjustment to add the agreed PCF allowance does not appear to have been done in the Draft Determinations and therefore is not included in the Totex values stated in the NGET Annex. This error will need to be corrected ahead of Final Determinations</p> <p><u>NGET Proposal: We agree this is an appropriate approach</u> We will continue to separate the PCF requests from the baseline view in our response to NGET201 to support the approach taken by Ofgem.</p> <p>In Final Determinations, Ofgem must correctly add the agreed PCF allowance as a post-modelling adjustment to the CAI allowance awarded.</p>
T2 /T3 Crossover	<p><u>Ofgem position at DD: most T2/T3 crossover projects have been excluded from assessment</u> In line with the treatment of the direct costs associated with these projects, Ofgem has removed the indirect costs of these T2/T3 crossover projects from the scope of its assessment at Draft Determinations. At Ofgem's request, NGET provided the CAI data in this format in response to SQ NGET171.</p> <p>Through its assessment, Ofgem has reclassified 101 non-load projects from T2/T3 crossover to T3 funding and assessed via the Project Assessment model. However, the indirect costs associated with these projects were not similarly assessed in the Draft Determinations and remain excluded. We note Ofgem's footnote 75 on page 146 of the ET Annex references this discrepancy will be resolved for Final Determinations.</p> <p>Ofgem has confirmed (para 5.131) that the T2 opex escalator will continue to apply for legacy RIIO-ET2 UMs where applicable.</p> <p><u>Issues with Ofgem's position</u> Please see our comments in ETQ39 for our full response on T2/T3 crossover projects.</p> <p>Issue 1 There are two categories of T2/T3 crossover projects, marked with separate project flags in the BPDts. Those that have funding via T2 mechanisms "T2 cross over (no costs assessment)" and those that do not "T2 crossover – assessment on T3 spend".</p> <p>It is the latter of these two categories that raises concern, with c. £300m of T3 indirects funding requested. There is currently no funding for these projects in T2 mechanisms and with no assessment in T3, there remains a significant gap in funding of both the direct and indirect costs.</p> <p>Issue 2 The choice to reclassify some projects but not the indirects associated with them complicates the understanding of the modelling that Ofgem has undertaken and means that the Draft Determinations position set out by Ofgem is understated by £104m. This will need to be corrected by Final Determinations.</p> <p>Issue 3 With a large proportion of the capex CAI removed from the assessment, the "fixed" opex costs form a larger proportion of the values being assessed. These proportions will not be the same as in the T2 period upon which the historic regression model is based, undermining the validity of the regression relationship and therefore the calculated allowances.</p> <p><u>NGET proposed solution: T2/T3 crossover projects need to be considered for funding and not excluded</u> Ahead of Final Determinations, Ofgem must engage with us on the topic of T2/T3 crossover projects in general and appropriately consult on proposals ahead of Final Determinations, ensuring that the indirect costs of these projects are appropriately considered.</p>
T3 UIOLI (baseline)	<p><u>Ofgem's position at DDs:</u> The Indirect costs of these schemes have been excluded and not considered for assessment or funding</p> <p><u>Issues with Ofgem's position: Underfunding of investments as indirect costs have not been considered</u> The assessment of the indirect costs of these schemes has not been considered alongside the assessment of the direct costs, leading to the situation where direct funding has been awarded allowances but the associated indirect funding has not been provided, leading to an overall underfunded position</p>

	<p><u>NGET proposed solution:</u> Ofgem must align the position between direct and indirect costs of investments, ensuring that where direct costs have been awarded, the indirect costs associated with these investments are appropriately assessed.</p>
Opex adjustments	<p><u>Ofgem's position at DD: Normalisation adjustments made to NGET submission</u> The following normalisation adjustments were made to the opex portion of the NGET submission:</p> <ul style="list-style-type: none"> £100m Ofgem applied adjustment to reduce the opex. This has been calculated in proportion to the capex excluded items noted in the above lines of this table. £7m reduction for incremental costs associated with the staffing and running of our new second control room and standalone SCADA system that have arisen as a result of the NESO separation. Ahead of the Draft Determinations, NGET requested that these costs be excluded from regression modelling and separately assessed. However, it appears that these have instead been excluded entirely. <p>Further costs were also excluded from the regression modelling and assessed separately:</p> <ul style="list-style-type: none"> £152m reduction for Operational Training and £11m adjustment for Wayleaves, aligned with the T2 approach £95m adjustment to remove contractor indirect costs, for separate assessment via the outcome of the PAM. <p><u>Issues with Ofgem's position: the normalisation adjustments are incorrect and will lead to the underfunding of CAI</u> A fuller response, including calculations, is included in our response to SQ NGET201.</p> <p><u>Normalisation: £100m Opex Adjustment</u> The Opex CAI in our business plan submission is a broadly fixed cost which reflects the underlying costs of running the organisation. These are primarily labour costs for activities such as the staffing and running costs of our control rooms, the running of strategic power systems engineering studies, periodic asset management policy reviews etc. There is a small amount of variability to these costs, driven by the number of projects and the size of the NGET organisation, however, they are broadly fixed.</p> <p>Ofgem has chosen to remove £100m of these Opex costs through a normalisation adjustment. We understand this is to reflect the proportion associated with the capex items that have been removed from the assessment (noted above). Ofgem has not explained how this removed proportion will be assessed and efficient funding provided. In DDQ NGET006, Ofgem have confirmed that funding has not been provided within the proposed CAI UIOLI pot.</p> <p><u>Normalisation: £7m incremental costs for second control room and standalone SCADA system</u> These costs are the additional, incremental labour cost of maintaining a second control room and independent SCADA system, net of the amount previously paid to NESO under the General Service Agreement (GSA). This is an enduring incremental cost that had no basis in the historical spend, and therefore we requested that this spend was excluded from the regression modelling and separately qualitatively assessed.</p> <p>Instead, as a normalisation adjustment, these costs have not been assessed, and we remain unclear as to how these costs will be considered for funding.</p> <p><u>Other items excluded from regression modelling</u></p> <ul style="list-style-type: none"> We agree with the approach to exclude operational training and wayleaves. The adjustment for contractor indirects, whilst correct in principle has been incorrectly calculated, following the reclassification of projects from T2/T3 crossover to T3 funding. £24m has been excluded twice from the regression assessment, leading to the Draft Determination allowances being understated. This has been acknowledged by Ofgem in DDQ NGET052 and we expect the revised SQ NGET201 data will support this correction in Final Determinations. <p>Across these three items, [REDACTED] has been incorrectly removed from the Draft Determinations assessment and the awarded allowances.</p> <p><u>NGET Proposal: Ofgem should use the data in SQ NGET201 to inform the calculations for Final Determinations. Where adjustments are made these should be validated with the TO.</u></p> <p>The normalisation adjustments should be removed and Ofgem should use the data provided in NGET201 to inform the modelling. Any future adjustments made to figures supplied by TOs should be discussed and validated with the relevant TOs.</p> <p>No change is required for the Operational Training & Wayleaves exclusions.</p> <p>Regarding the contractor indirects exclusion, we anticipate further reclassifications of projects between these two categories following engagement with Ofgem. Upon completion of this exercise, Ofgem should ask TOs to reconfirm the baseline allowances associated with the revised project listing, to ensure this calculation error does not repeat.</p>

The modelling approach

We have concerns with the validity and statistical robustness of the modelling approach.

Figure 21 compares NGET's adjusted requested allowance (blue) against the allowance which would arise from Ofgem's regression (orange) and Ofgem's ratio analysis (green). The requested allowance incorporates all Ofgem's scope adjustments (i.e. the chart for now ignores the concerns we highlight above in relation to scope). The chart shows that the modelled output from the historic regression modelling is double the adjusted requested allowances.

This outcome is inappropriate. NGET has driven efficiency improvement across the T2 and T3 periods and embedded efficiencies from IT&T and Innovation investments amongst other things; and we have not made any significant changes in how the costs and spend are estimated between the T2 and T3 periods. It is therefore not credible to assume that this level of difference is driven by efficiencies, and it seems more likely that the discrepancy is an indicator of both the errors in normalisation adjustments noted above and underlying issues in the modelling.

The introduction of ratio analysis based on RIIO-T3 forecast data represents a positive shift from the RIIO-T2 approach, which relied solely on historical expenditure. By incorporating forward-looking forecasts, the methodology can in principle better capture expected cost trajectories, including step changes driven by the transition to Net Zero.

However, the fact that the ratio analysis produces results closer to NGET's requested costs than regression analysis, should not be mistaken for robustness. This outcome is largely due to its TO-specific design, where the absence of cross-TO benchmarking weakens efficiency incentives, as an inefficient TO could justify higher CAIs for a given level of capex and MEAV. Provided this inefficiency were consistent over time, such a TO would receive a higher allowance than a more efficient peer with lower CAIs – an outcome avoided under the comparative regression-based approach.

We note that the ratio analysis results also demonstrate the challenges that arise from data inconsistency between the TOs described above. **Figure 22** below shows the modelled CAI allowances for each TO arising from the ratio analysis, as well as the two variables used as the denominator (i.e. total capex and average MEAV). NGET has materially higher values for both drivers (capex & MEAV). This should mean the ratio modelled allowances would also be higher for NGET – but, as the left hand CAI chart shows, the ratio model actually indicates the appropriate allowance for NGET is lower than the other two TOs. This result could only happen if NGET is significantly more efficient, or (more likely) that the CAI costs have been submitted on a different basis. Whilst every network should receive funding for their efficient spend, it does not appear that the current methodology achieves a fair or credible outcome.

The use of the ratio analysis to provide 50% of allowances, when combined with the data comparability issues, means that TOs will receive ex ante allowances on a different basis. This will further complicate the approach and calibration of the pipeline mechanism (as discussed in ETQ58 below). As it currently stands, the TOs are being funded for different things in the baseline, which will result in differing requirements for what the pipeline will cover.

Figure 22: Comparison of ratio model outputs across the three TOs alongside the two drivers of Capex and MEAV

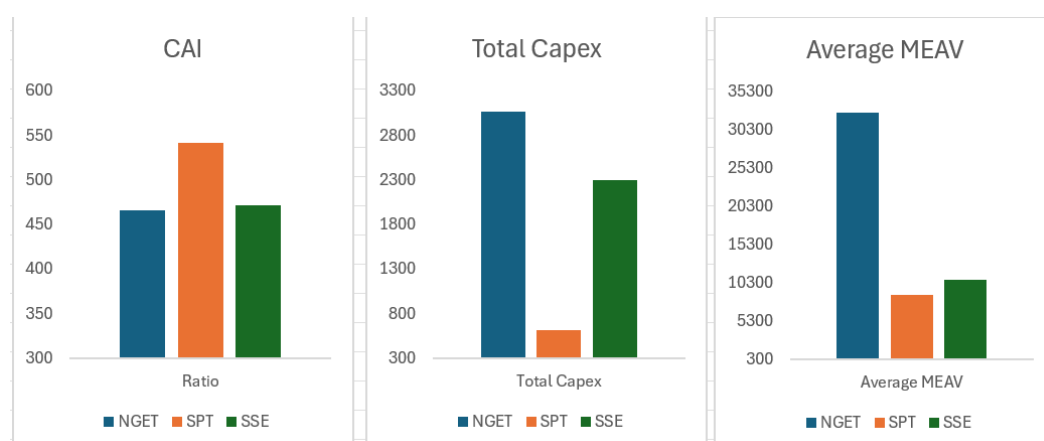
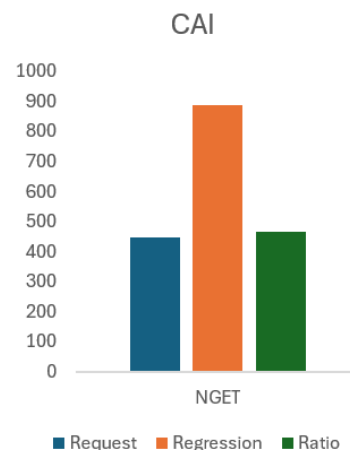


Figure 21: Output of regression and ratio models compared to normalised NGET request



Disaggregation of CAI Costs

Our baseline CAI spend consists of two types of CAI.

- **Non-project specific “Opex” CAI** (sometimes referred to as “fixed costs” by other TOs, reported in the Business Plan Data Table 9.4). These are underlying costs (primarily staffing) necessary to run the business and which are not specifically related to capital projects.
- **Project specific “Capex” CAI**: this includes direct project-related costs such as project management. The absolute magnitude of these costs is driven solely by the number and size of projects that are being undertaken.

The proposed disaggregation of CAI has been discussed in Cost Assessment Working Groups, with the intention of appropriately separating these project specific and non-project specific costs to develop more robust and accurate cost assessment models. This is a step that has been supported both by Ofgem and TOs. However, the nature of this categorisation has not been agreed, with the definitions proposed by Ofgem (“very” and “other CAI”) not closely aligning with the actual different drivers of costs in the NGET business.

In particular, a significant amount of project specific spend remains within Ofgem’s “other CAI” category (e.g. portfolio management and costs associated with project specific safety & incident management would be categorised as “Engineering Management & Clerical Support (EMCS)” and “Health, Safety and Environment” respectively). To model these costs appropriately, they should be aligned to a capex driver.

As a result, if Ofgem were to use its proposed categorisation in the benchmarking, this would lead to less robust results compared to the Opex CAI and Capex CAI split. Further, the Opex / Capex split is preferable since it is based on accounting definitions, meaning categorisation should be consistent across TOs and subject to the annual external audit process.

Given the limited time now available before Final Determinations, we propose that a disaggregation methodology is explored for future price controls rather than incorporated into the T3 assessment approach, especially given the noted data inconsistencies between the TOs which are a much greater priority to resolve. We would encourage Ofgem to engage early on this topic in future, to avoid the issues that we have seen in the RIIO-T3 process.

Treatment of Contractor Indirects

We agree with Ofgem’s decision to assess Contractor Indirect costs separately, outside the econometric modelling. We are comfortable with the treatment as being aligned to the outputs of the Project Assessment Model.

However, as has been discussed through the RIIO-T2 reopener assessments and RRP cycles, for reporting purposes the definition of contractor indirects is unclear and leads to inconsistencies depending on the delivery method chosen. For example, if a project is TO-delivered, certain activities such as site preparation and readiness works would be reported as per the RIGs as indirect costs. However, the same activities in a project being delivered by a contractor would be reported as direct costs. This leads to differences both in reporting, but also in funding allowances. This is not correct and this definition needs to be addressed before incorporating any Contractor Indirects into the CAI reporting.

ETQ58. Do you agree with the CAI UIOLI allowance to support TOs growth ahead of CP2030? What are your views on the scope and chosen level of CAI UIOLI funding?

We do not agree with the introduction of the CAI UIOLI allowance for RIIO-T3; nor with the proposed scope and level of funding proposed by Ofgem. The proposed approach increases complexity and regulatory burden whilst reducing clarity and incentives to find efficiencies that would benefit consumers.

Instead of using a UIOLI allowance, Ofgem must implement either of these alternatives:

- **Option 1 – this is our first preference:** assess pipeline projects as a whole (i.e. a ‘gross capex’ assessment, in the same way Ofgem propose for larger load schemes and all non-load schemes); or
- **Option 2:** use a simple, formulaic ‘indirects scalar’ mechanism, similar to the RIIO-T2 opex escalator approach.

We discuss these two alternatives further in our response to ETQ59 below, where we explain our preference for Option 1 as the most straightforward approach. However, relative to either of these two alternatives, Ofgem’s Draft Determination approach:

- 1) involves substantially greater complexity and regulatory burden;
- 2) provides substantially less clarity and certainty that the necessary level of funding will be allowed; and
- 3) reduces incentives to find efficiencies that benefit customers, at a point in time where those incentives have the greatest potential to benefit customers in both the short and long-term.

In relation to 1), Ofgem proposes to introduce multiple varying approaches across the cost base, which we summarise in the table below.

	Under £25m	£25m - £150m	Greater than £150m
Load & Volume Drivers (with PCF)	No indirects funding	PCF funding awarded at 2.5% of expected capex	
Load & Volume Drivers (without PCF)		CAI UIOLI allowance at 10% of expected capex	Gross capex assessment via project assessments
CSNP schemes	Unclear in Draft Determinations		
ASTI schemes	Gross capex assessment via project assessments (ASTI benchmarking template)		
Non-load schemes	Gross capex assessment via project assessments		
Other incremental non-project specific indirect costs	No funding		

This approach would significantly complicate the regulatory framework, creating numerous boundaries between cost categories and projects. This would inevitably lead to additional regulatory burden for both TOs and Ofgem to report and monitor these different cost treatments as highlighted by Ofgem’s mention (ET Annex paragraph 5.130) for additional reporting requirements. The multiple mechanisms would also create a risk of confusion and debate about whether funding has been awarded or not. This risk has already crystallised into an issue through the RIIO-T2 period, and the RIIO-3 Draft Determination proposals only exacerbate this issue further.

This would inevitably slow down decision making and TOs ability to deliver the work necessary to deliver CP2030 and Net Zero. Across the RIIO-T3 price control, Ofgem has stated that it is targeting a simpler and more automatic regulatory framework which gives TOs certainty of funding routes, timely access to allowances for efficiently incurred spend and will drive efficiency by reducing the amount of in-period regulatory work for both TOs and Ofgem. However, the Draft Determination approach for CAI UIOLI appears to do the opposite. It can be expected to delay the approval of pipeline projects at a time when pace of delivery is the most important objective for customers and Government.

In relation to 2), this is because the proposed UIOLI allowance is materially too low – largely because of a range of errors in the scope of allowance which Ofgem has set and the level of funding provided (detailed further below). This means Ofgem will have to introduce a process for revisiting the allowance within the period, which as yet is not specified in the Draft Determinations.

While we note Ofgem’s comments on the fungibility of the upfront allowance across projects, we are concerned that there will not be a simple mechanism for triggering an update to the UIOLI allowance. We note, for example, the lengthy debate on T2 reopener projects as to whether indirects had been funded, leading to delays in the regulatory approval of

projects (e.g. the reopener application for Dinorwig-Pentir took approximately 18 months from submission to determining allowances). The overly complicated mechanisms for RIIO-3 would further exacerbate this issue.

Ofgem also indicates that its reason for introducing UIOLI is because it provides TOs with upfront certainty of funding. However, this potential benefit is undermined by the complexity outlined above; and in any case would already be addressed by:

1. Ensuring that the “fixed / opex” CAI costs incurred by the TOs are appropriately funded in the ex-ante allowances (discussed in ETQ57 above); and
2. A well-designed pre-construction funding mechanism, with the scope widened further to include non-load projects (see response to ETQ26).

The remainder of this response provides more detail on the errors Ofgem has made in its proposals on the scope and level of funding for its UIOLI allowance.

Scope of the UIOLI allowance

The scope proposed by Ofgem in the Draft Determinations creates arbitrary divisions between different types and sizes of projects which further complicates the regulatory framework, with eight different categories and approaches across load and non-load projects and the incremental non-specific project costs.

Scope – Load & Connections Volume Driver projects

The proposal in Draft Determinations sets out five different approaches for Load projects:

1. Load projects with spend under £25m
2. Load projects with spend between £25 - £150m
 - a. Projects for which pre-construction funding has been awarded
 - b. Projects for which there is not currently pre-construction funding
3. Load projects greater than £150m
4. ASTI projects
5. CSNP-F projects

For **load projects with spend lower than £25m**, Ofgem has proposed no incremental indirects funding and suggests that the ex-ante funding would be sufficient. This is incorrect, because ex ante funding is provided only for the narrow scope of projects that Ofgem has defined as baseline (as discussed in response to ETQ57 above). Ofgem’s allowances are capped at our submitted request for the defined projects – and therefore no additional funding for other projects is included in this ex-ante funding. Ofgem’s load UIOLI allowance for the direct costs of these “lower materiality projects” is [REDACTED], which would normally be expected to entail up to [REDACTED] of indirect spend. This creates an arbitrary different treatment for these projects and a clear gap in funding which must be addressed in the Final Determination.

For **load projects with spend between £25m - £150m**, there are two different categories depending on whether pre-construction funding (PCF) has been awarded as part of the ex-ante allowances. Projects for which PCF has not been awarded are within scope of the UIOLI allowances. However, for projects where PCF has been awarded ex-ante at 2.5% of project spend, no further provision has been made and therefore the remainder of the indirect costs associated with those projects have not been considered for funding. Ofgem must correct this error (if the UIOLI allowance is retained) by setting the proposed allowance to include the indirect costs, net of the ex-ante PCF within the scope of the CAI UIOLI allowances.

For **load projects greater than £150m**, the flow chart on page 149 of the ET Annex indicates these will be assessed as part of the project assessment and therefore we infer a gross capex assessment. Ofgem has confirmed in DDQ NGET069 that it has not yet developed the approach to assess funding for these projects but suggest it may be similar to the benchmarking approach used in ASTI. We agree that a gross capex assessment (direct + indirect + risk) is the most appropriate for this type of major project.

For **ASTI projects**, both above and below the £150m threshold, we understand that the existing ASTI regime for indirects will continue to operate. This involves a benchmarking template that assesses projects as a whole (the gross capex approach), and we agree this is the correct approach. However, as detailed in our response to ETQ57, Ofgem must ensure that indirect overhead costs associated with these projects has a route for funding, which is currently missing.

Finally for **CSNP-F projects**, Ofgem has provided no detail as to the funding of the associated indirect costs, for which a new reopener mechanism is proposed. Whilst stating that these projects will qualify for PCF, it is not clear through which mechanism the remaining indirect costs of the projects will be assessed.

Scope – Non load projects

Non-load projects have not been included in the proposed CAI UIOLI allowances. Instead Ofgem states (ET Annex paragraph 5.131) that “*indirects funding can be requested for non-load reopener projects through the project assessment process for re-openers*”. We understand this to mean that non-load projects in the pipeline will be assessed by a gross capex assessment (i.e. both direct and indirect costs), no matter their size.

For context, our pipeline contains non-load projects that range in size from [REDACTED] and have an associated anticipated forecast CAI of over [REDACTED]. Whilst we generally believe that it is more appropriate to undertake gross capex assessment of all projects, it introduces unnecessary complexity and confusion to have a different approach for pipeline load and non-load projects. Ofgem needs to align all load and non-load projects to the gross capex approach outlined for the non-load reopener.

Scope – Other Indirect Costs

Ofgem has provided UIOLI allowances for only indirect costs that are directly associated with projects and does not consider the incremental fixed costs that arise as the organisation scales and grows.

Whilst relatively small (assuming the normalisation adjustments referenced in ETQ57 are corrected), these costs either need to be:

- awarded upfront,
- included explicitly as a separable item within the CAI UIOLI allowances, or
- appropriately calibrated into an indirects scalar.

We believe the provision of the “best view” forecast that we anticipate Ofgem to request via the SQ process will facilitate the inclusion of these incremental costs.

Level of funding

The proposed “conservative” position of [REDACTED] for the level of the CAI UIOLI pot is arbitrary, not appropriate or evidenced. It would lead to significant underfunding of NGET’s pipeline projects. If appropriately calibrated we would expect this figure to align to the [REDACTED] figure associated with NGET projects ([REDACTED] NGET indirects and [REDACTED] contractor indirects). We note our costs have been deemed to be efficient under Ofgem’s efficiency models.

The use of ED2 as a reference point is inappropriate as the types of projects being delivered in terms of nature, complexity, size and volume are significantly different between the transmission and distribution networks. The drivers and types of indirect costs associated with these projects are therefore significantly different. By their nature as larger and more complex projects, transmission projects necessarily face significantly greater planning, consenting and project management costs than those seen in distribution, making the indirect costs of the projects incomparable. The majority of projects in Electricity Distribution are below the £25m threshold being proposed by Ofgem as “low materiality projects”, showing the fundamental differences between the work delivered by the two sectors.

For comparison, the NGET T2 Opex escalator used a scaling factor of [REDACTED] (prior to the NOCs uplift) and the T3 regression models suggest a relationship between capex and CAI of [REDACTED] (before any further associated MEAV uplift). These would be a much more appropriate starting point for the calibration of a CAI UIOLI allowance or indirect scalar mechanism.

Furthermore, neither of these reference points include contractor indirect costs that have been assessed outside of the indirects statistical modelling in both T2 and T3. If Ofgem intends for TOs to continue reporting these costs as part of the indirect costs in T3 (subject to the need to clearly define them as discussed in response to ETQ57), the CAI UIOLI pot will need to be appropriately calibrated to include these costs. NGET applied a standard percentage of [REDACTED] of project cost as being the contractor indirect costs associated with a project in the T3 submission that would need to be included.

Whilst this calculated percentage is different for each of the TOs, there is precedent via the T2 opex escalator to award different scaling values for each of the TOs. We think this may be an appropriate point of difference that needs to be included in T3 until the data differences can be resolved. The treatment of contractor indirect costs has been a source of significant confusion and debate through the T2 period; it is essential to resolve this confusion and the revised approach to be referenced explicitly in the setting of the T3 calculations within Final Determinations.

Should Ofgem persist with the proposed CAI UIOLI allowance, or alternatively adopt a simple indirects scalar mechanism, the information provided in the SQs requested during the Draft Determination period (to resubmit the “baseline” and “best view” forecasts) should be used to appropriately calibrate these mechanisms. Ofgem should explore a range of different models that consider differing options and weightings of drivers including 1) the “Best View” forecast position as a whole; 2) the baseline and pipeline spend separately. In any case, Ofgem must ensure that the contractor indirect costs are subsequently added as a post-modelling adjustment. We would expect Ofgem to consult on and share these models prior to publication of the Final Determinations.

ETQ59. Do you agree with our proposal to remove the opex escalator for RIIO-ET3?

Our view on this question depends on how Ofgem sets CAI allowances:

- We do not agree with the proposal to remove the opex escalator in RIIO-ET3 if the alternative proposal is a CAI UIOLI allowance
- We agree with its removal if all pipeline projects be assessed whole (via gross capex assessments) as an alternative approach to setting CAI allowances, as discussed in ETQ58.

In ETQ58 above, we detail our concerns with the CAI UIOLI allowance and provide two alternative proposals:

- **Gross Capex Assessment:** Extend the gross capex assessment approach to all pipeline projects, both load and non-load.
- **Indirects Scaling Mechanism:** Implement an updated version of the T2 opex escalator. Both this option and the CAI UIOLI allowance proposed by Ofgem would require additional work across Ofgem and TOs to agree a clearly defined, updated set of RIGs which remove the ambiguity and potential for interpretation in the classification of costs between direct and indirect. This is required to avoid the lengthy debates that arose through the T2 period and contributed to the delayed approval of reopeners.

Ofgem must assess pipeline projects as a whole (i.e. a 'gross capex' assessment) in the same way Ofgem proposes for larger load schemes and all non-load schemes, and this would not require an opex escalator.

Gross Capex Assessment

Ofgem's Draft Determinations propose to use the gross capex assessment approach inconsistently across the pipeline, applicable to all non-load projects but only larger load projects. We instead suggest that the pipeline mechanisms should be simplified, and this gross capex assessment approach extended to all load and non-load pipeline projects.

The T2 period re-opener project assessments have consistently underfunded TOs, with long debates as to whether specific portions of spend have been previously funded and under which mechanism – for example, in the recent T2 MSIPs application, for which the direct costs are assessed and the indirects are funded via the opex escalator. These have been reviewed against unclear and subjective RIGs, leading to consultation positions that propose to disallow immaterial amounts of costs that are deemed to be indirect costs, which are then debated. This unnecessarily detailed, time-consuming review is not in the interest of either TOs or consumers, as it delays the approval and subsequent delivery of essential projects. This could be avoided by a simple gross capex assessment of projects, where the full costs of a project are assessed at the same time and without arbitrary categorisation.

Furthermore, considering and reviewing a project whole ensures that a project will be delivered in the most efficient way rather than a mix of mechanisms combining to drive commercial decisions. For example, as discussed in the Contractor Indirects section of our response to ETQ57, different delivery choices between self-delivered and contractor-delivered would receive different levels of funding under a split direct / indirect assessment methodology. This complication is not in the interest of consumers and would not arise if a gross capex assessment were used.

Finally, the gross capex assessment would remove the impact of differing interpretations of RIGs across the TOs as these categorisations would not impact the costs being put forward for assessment. As a result, Ofgem would be better able to make use of cross-TO benchmarking and support the drive to deliver projects in the most efficient and cost-effective way.

To simplify the assessment process, guiderails could be set that would speed the approvals without the need for detailed reviews. For example, if the indirect costs are below or within a defined benchmark then the indirect costs should be automatically approved or with only a light touch review undertaken. We suggest these defined benchmarks could be set with reference to the pipeline regression modelling discussed in ETQ58 above, using the data provided for both "baseline" and "best view" forecasts to inform an appropriate relationship between the indirect costs and the capex spend - as will need to be done to inform the correct funding level for a CAI UIOLI allowance.

We consider two challenges with the gross capex assessment approach.

- First, this approach would not appropriately fund any incremental non-project specific (opex) costs that arise as a result of the pipeline spend. As we expect this incremental spend to be relatively small, we suggest that Ofgem could mitigate this risk by adopting the 'baseline plus uplifts' approach that is proposed for the BSC ex-ante allowances.

- Second, this approach provides TOs with less certainty relative to a mechanical scalar approach. However, the combination of a well-designed PCF framework (that provides access to accelerated CAI funding ahead of project assessment) and the benchmarked guiderails approach (that we propose for the operation of the gross capex assessments) should provide sufficient certainty for TOs. Furthermore, the simplified framework would likely give more certainty to the cost assessment process overall and would therefore mitigate the risk faced by TOs under the Draft Determination proposals.

Indirect Scalar

On the other hand, a well-designed and calibrated indirects scalar mechanism provides certainty of access to funding for TOs through a simple and mechanistic approach. This therefore enables TOs to confidently invest – which was part of Ofgem's rationale for its UIOLI proposal (particularly if implemented alongside sufficient ex-ante allowances and a well-designed PCF policy). Consumers would be protected through ensuring the scalar is well-calibrated; and would also benefit from any efficiencies via the Totex Incentive Mechanism.

However, as with Ofgem's CAI UIOLI approach, a scalar could still face problems with a lack of clarity in RIGs and differing interpretations leading to an onerous cost assessment process for reopener projects. This would need to be addressed to streamline the process for project approvals and prevent delays. It would also retain the complication and drawbacks of the multiple different mechanisms being used to assess indirect costs associated with pipeline projects.

Finally, an indirects scalar would need to be appropriately calibrated, similarly to the approach required for the appropriate level of funding for the CAI UIOLI allowance. It would be important to ensure that contractor indirect costs are not missed from this calibration, as they are not assessed alongside baseline indirect costs. Our proposals for this would be the same for either mechanism, and are therefore addressed in detail in ETQ58 rather than being repeated here.

Summary

In summary, the gross capex assessment of all load and non-load pipeline projects would be an improved approach, which would mitigate many of the errors and issues that have arisen in the T2 period relating to the project assessment of reopeners and delays to approvals caused by detailed reviews. This would provide comfort and certainty in the form of a simplified framework that does not create arbitrary divisions in project costs, and lead to a simplified approval process that drives networks to deliver in the most efficient way.

Alternatively, a well-designed and properly calibrated indirects scalar mechanism would provide certainty and an efficiency incentive while reducing the regulatory burden to support TOs to scale up. This would allow TOs to deliver the significant workload that is required for CP2030 and Net Zero. Ofgem has used opex escalators in the past because of these clear benefits and, both recognising these precedents and the fact that pipeline spend is inherently uncertain, it is a flawed approach for Ofgem to propose to instead set a capped UIOLI allowance upfront.

ETQ60. Do you agree with our approach to BSC? How do you think this could be improved?

We do not agree with Ofgem's current approach to BSC. There are data inconsistencies between TOs which still require further work to resolve, data has not been included in the analysis, and a further review of the modelling approach is needed.

Ahead of Final Determinations, Ofgem must:

- Ensure that TOs data is based on comparable scenarios
- In calculation of the baseline allowances, use the "best view" SQ response to ensure uplifts are appropriately included
- Ensure that all costs are assessed and consider the evidence in NGETQ10 regarding the FOE scheme
- Undertake a robust modelling review that assesses alternative drivers in the BSC trend analysis modelling

Our specific issues are summarised as follows:

First, Ofgem must ensure the TOs' data is based on comparable scenarios so as to ensure consistency in awarded allowances. As noted in our response to ETQ57, there are significant data consistency issues across the TO submissions. We welcome the attempts made by Ofgem to drive greater consistency in the forecasts via the SQ (NGET201) issued since the Draft Determinations.

Since the direction requested in Cost Assessment Working Groups prior to the Business Plans, there has been limited new guidance from Ofgem as to how these inconsistencies should be resolved. We therefore remain concerned that the SQ will not achieve the aim of gathering consistent data and will not resolve the issue of TOs being treated consistently and fairly in the modelling approach.

Second, and relatedly, Ofgem needs to correct its error in capping our allowances at the level of submitted costs, when we submitted BSCs only in line with our baseline spend while the other TOs requested allowances to deliver their pipeline. This leaves us at a structural disadvantage, since Ofgem's approach fails to achieve its intended effect of uplifting BSC allowances to reflect the growth in the TOs' pipelines. This also has knock-on implications for Ofgem's proposed BSC reopener which must be addressed.

Third, Ofgem should correct the error that it has failed to provide allowances for ETCC additional property costs [REDACTED] which were normalised out of the regression analysis but have not been allowed. In addition, if the [REDACTED] allowed (see NGETQ10), the associated indirects for that scheme must also be allowed for ([REDACTED]).

Our response to this question excludes IT&T Business Support Costs (addressed in ETQ52), in line with Ofgem's treatment through the assessment and discussions in Cost Assessment Working Groups.

The remainder of this response is structured in the following way:

- Data consistency & uplift approach
- Scope of assessment – normalisation and exclusion adjustments
- Historical Baseline Regressions
- Trend Analysis

Data consistency & uplift approach

As with CAI, much of the difficulty arises from the question of whether allowances should be awarded in relation to the baseline or whether a "best view" of total indirect spend should be awarded upfront.

Typically Ofgem provides ex-ante allowances where there is more certainty (with uncertainty mechanisms capturing allowances where the amount of work is materially uncertain). We therefore provided a BSC forecast in our business plan consistent with the projects, assets and size of the organisation that are required to deliver our baseline spend only. Our forecast therefore did not include all the BSC costs that would be needed in the T3 period to deliver the full pipeline.

To illustrate this with the example of insurance, our BSC submitted figures of [REDACTED] cover the costs to insure our existing assets and those that will be installed as part of baseline. As projects in the pipeline are approved and delivered, this will deliver additional assets, which will drive an incremental increase to our cost of insurance. These incremental costs are not included in our business plan submission.

We understand that by using the forward-looking trend analysis (alongside the backward-looking regression), Ofgem intends to provide an uplift to the baseline BSC allowances, reflecting this anticipated increase in BSCs for pipeline projects. However, in NGET's case, despite the modelled figures for both the historic regression modelling and the trend

analysis being higher than our submitted request, the awarded allowances in Draft Determinations have been capped at our submitted baseline value. As a result, allowances for incremental BSCs due to pipeline projects have not been awarded to NGET, in contrast to other TOs (who provided their forecast on a different basis).

NGET will provide a forecast on a consistent basis to the other TOs via the “best view” indirects SQ that Ofgem will issue imminently. We expect that this “best view” forecast figure will be used as the corrected allowance cap in the Final Determinations, creating greater consistency across TOs.

Scope of BSC assessment

The below points are also addressed in our response to SQ NGET201 sent alongside this consultation response.

Ofgem made two normalisation adjustments to the NGET submitted figures used in the historic regression modelling, but these have not been removed from the trend analysis. This is not correct and instead they should be removed from both methods, considered separately, and added back as a post-modelling adjustment (as is done for insurance for example). The normalisation adjustments are:

- **ETCC additional property costs (█████)**: Facilities management costs associated with the second control room that is currently under construction and due to complete in 2028. NGET requested that these costs be excluded from the regression modelling and assessed separately as there is no equivalent prior spending, and therefore the regression model run rates would not appropriately fund these incremental costs. In the Draft Determinations, Ofgem removed these costs through the normalisation adjustments and provided no information as to how these will be considered or assessed.
- **BSC associated with ██████████**: These are one off costs directly associated with the ██████████ (██████████) non-ops capex scheme (details of which can be found within the EJP & CBA). Again, NGET requested that these costs be excluded from the regression / trend modelling and qualitatively assessed as part of the review of the associated EJP. In the Draft Determinations, Ofgem removed these costs through the normalisation adjustments and disallowed the ██████████. Please see our response to NGETQ10 for our more detailed response on this scheme. This scheme should be supported through the Final Determinations and allowances awarded accordingly.

Modelling - Baseline Regression & Trend Analysis

In an attempt to recognise the step change in workload and delivery between the T2 and T3 periods, Ofgem has introduced a simple trend analysis that models BSCs based on a simple uplift in line with the percentage growth in FTEs. This trend analysis sits alongside a baseline regression model that considers only historic costs.

As explained further in our response to ETQ57, the trend analysis involves no comparative assessment between TOs and therefore places too great a weight on individual TO forecasts. This creates inconsistency between TOs based on what was included in the forecast; creates further issues in designing a suitable pipeline mechanism; and has the potential to reward inefficiency in forecasts.

As Ofgem is continuing to collect the “best view” data from the TOs, and subject to ensuring the data being used is on a consistent basis, it would be more appropriate to return to the single regression modelling approach but using “best view” forecast data. This would have the benefit of using both historical and forecast data and ensuring the TOs are assessed comparatively. It would also provide greater certainty on what has and has not been included in the ex-ante funding, therefore simplifying the use of the BSC reopener (or alternative BSC scaling metric) should it be required.

On the trend analysis in particular, we are surprised by the choice of “best view” FTE as the driver for the calculation. In the Draft Determinations (paragraph 5.139), Ofgem states that FTE is a “robust driver of BSC costs that has been affirmed through our regression work and has regulatory precedent”. However, the regression analysis uses a composite scale variable for which FTE makes up only 11.5% of the cost driver. This indicates that FTE is not considered a significant driver of the historic spend, with MEAV forming a much greater proportion. Ofgem may have chosen to use FTE because it had this information on a consistent basis across all three TOs. The upcoming SQ with “best view” MEAV on a consistent basis means Ofgem should explore the use of this as an alternative driver in Final Determinations (should this modelling approach be retained).

ETQ61. Do you agree with our proposal to introduce a BSC Re-opener? What are your views on the proposed design? What alternatives to a BSC Re-opener do you see as viable?

We do not agree with Ofgem's proposal to introduce a BSC reopener. The proposed reopener fails to give TOs certainty of funding routes, will not provide timely access to allowances for efficiently incurred spend, and will increase the amount of in-period administrative burden for both TOs and Ofgem.

Our specific issues are summarised as follows:

- **15% threshold on BSC outturn costs.** Ofgem's benchmarking shows that NGET's requested baseline allowances are efficient. Further BSCs will arise as a result of the pipeline growth. While we understand that Ofgem's intention is to provide some but not all ex-ante funding to support this growth, in practice this is not the case for NGET and needs to be addressed, as discussed in response to ETQ60. The reopener design means that any incremental BSCs will not be funded unless outturn BSCs are above 15% of allowances (excluding IT&T costs as indicated by Ofgem at CAWG22 on 30th July 2025).

At a 15% threshold, NGET could incur almost £60m of efficient incremental BSCs across the T3 period for which no funding would be provided. We do not anticipate our incremental BSCs will reach this threshold, especially if the ex-ante allowances are appropriately uplifted, and therefore do not anticipate the reopener to be triggered. This means that efficient BSC costs that we will necessarily incur are simply not funded under Ofgem's RIIO-3 framework, creating further downside risk.

- **15% threshold on non-variant totex.** The problem above is further exacerbated if Ofgem is applying the threshold at a Totex level rather than at BSC level. Even if Totex spend across the rest of the cost base is in line with allowances, we could in theory incur substantially more than £60m of efficiently incurred BSCs without the Totex threshold being triggered. This is wrong and will underfund the sector.
- **Timing of the mid-period review.** A mid-period review means that in practice only one or two years of outturn data is likely to be available by the time that TOs are collating their submissions. Much of the incremental spend may not have been triggered by this point, as many pipeline projects will have only recently been approved or still awaiting approval at this stage. The result is that the likelihood of triggering the reopener is further reduced.

To illustrate these points with a specific example of insurance costs, these costs have been modelled through a cost assessment using network length as the driver, with existing asset data and the asset volumes from baseline projects. As projects in the pipeline are delivered, these additional assets will lead to increases in the insurance premiums in the latter years of the T3 period. We estimate this to be c. [REDACTED], which is less than 10% of the total insurance allowances, close to only 1% of the total BSC allowances and a negligible impact on the overall Totex allowances. This increase in costs would be efficient but would not on its own trigger the reopener thresholds proposed by Ofgem. As a result, it would be a further unfunded challenge that needs to be absorbed by the TOs.

- **Mechanics of the reopener.** The Draft Determinations provide no information as to how Ofgem will assess reopener allowances. In the CAWG22, Ofgem confirmed that it does not intend to make this decision at this time, instead leaving it for discussion at the point of the reopener. This creates a huge amount of uncertainty for the TOs about how funding for efficiently incurred costs will be assessed and accessed, creating a barrier to TOs to invest and spend ahead of certainty.

Should Ofgem go ahead with the BSC reopener, Ofgem must consult on the approach the mechanics of the reopener ahead of Final Determinations.

However, even considering options at a high-level demonstrates that the overall BSC re-opener mechanism is unworkable and must itself be revisited (as explained above):

- While we would prefer a quantitative, mechanical mechanism, aligned to our ambition to simplify the regulatory framework, we consider that this is unlikely to work in practice. This is because comparative data would not be available if only one TO triggers the reopener and therefore comparative benchmark regressions could not be used. We do not believe that Ofgem would be comfortable performing the analysis based on the simple trend analysis methodology alone.
- Alternatively, a qualitative assessment may aim to take these considerations into account. However, we anticipate Ofgem would require a significant level of reporting, information and evidence to demonstrate that the costs have been efficiently incurred, therefore increasing the regulatory burden for both the TOs and Ofgem and creating uncertainty for TOs on what information will be required. This is particularly the case if Ofgem does not confirm this

at the start of the price control period, meaning that TOs are not sufficiently set up to be able to collect the suitable information.

Instead of the proposed reopener, Ofgem must implement one the following options:

- **Option 1: Ex-ante allowances consider the total T3 BSC forecast and appropriately weight the inclusion of the forecast data to ensure sufficient ex-ante funding is awarded. We believe this upfront funding approach is appropriate to ensure that all efficiently incurred BSC are funded, particularly in light of our expectation that these will be relatively small. However, we recognise that this may not be the case for all TOs and recognise Ofgem's reticence to award full upfront funding.**
- **Option 2: Use the indirects scalar mechanism that we outline in ETQ58 and ETQ59. A small, incremental uplift can be added for BSCs, as was done with the NOCs uplift in the T2 period. The data provided by the TOs via the "baseline" and expected "best view" SQs (should these be deemed to be consistent) will provide appropriate data, which can be used to calibrate a value for this uplift percentage via regression or other simpler modelling. This would require a clear decision about which types of projects the scaling mechanism would apply to.**

ETQ62. Do you agree with our approach to MEAV? What do you think we could do to improve its robustness?

We do not agree with the proposed calculation of MEAV as we disagree with the exclusion of a significant number of assets and remain concerned about the consistency of the data across TOs.

Ofgem's approach of excluding assets due to the category of project that has delivered those assets undermines the purpose of the MEAV metric as a variable to predict the indirect costs of the business and must be addressed prior to Final Determinations. Moreover, the data shared in the Draft Determinations indicates that work is still required to ensure TOs are reporting MEAV consistently.

MEAV is used to represent the size and complexity of a TOs network and is used in the regression modelling to predict the indirect costs associated with running the network. There are three key factors in the calculation of MEAV:

- Which asset types to include
- Unit costs for those assets
- Calculation of the asset volumes

In the T2 assessment, it was recognised that the TOs were calculating MEAV inconsistently, with different unit costs and different types of assets being used across the three TOs. This inconsistency affected the reliability of MEAV as a metric used in the benchmarking and Cost Assessment Working Groups have worked to improve this in the lead up to the price control. The aim has been to identify both a consistent asset list and a set of unit costs that are applied to all TOs.

We are pleased with the improvements that have been made, in particular the use of a standardised unit cost applied to all TOs. However, we are concerned that this has not gone far enough to resolve the consistency issues which continue to undermine the metric, and we are particularly concerned by the third item – the calculation of the asset volumes – which has not previously been explored as an issue.

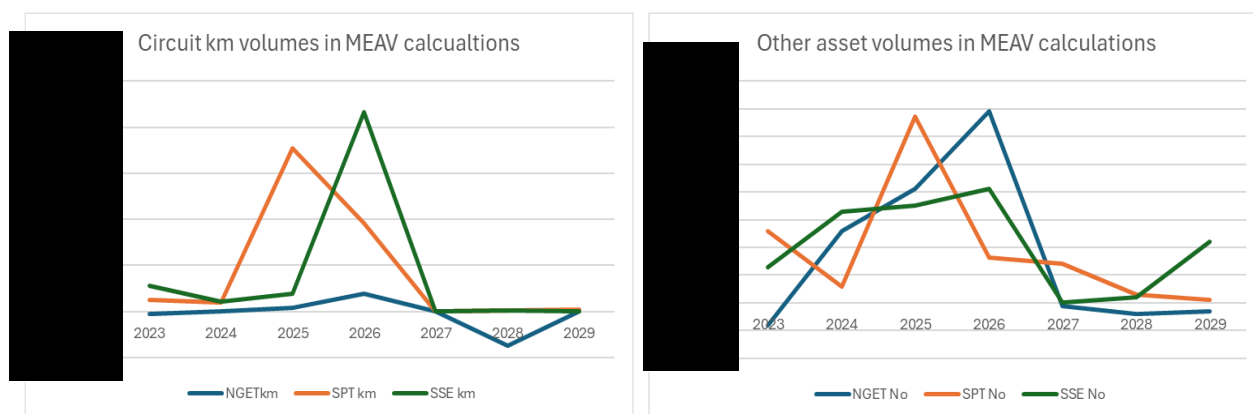
Our main concern is Ofgem's decision to exclude certain asset volumes from the MEAV calculation based on the project category. This is a new approach not used in T2 or the ED regulation, which uses the same metric. We understand that Ofgem has tried to remove assets related to projects out of scope of CAIs (see response to ETQ57), such as asset volumes from the T2 / T3 crossover schemes and the ASTI projects. However, this approach is fundamentally flawed as all assets drive costs irrespective of the project mechanism through which it was delivered, and the organisation should be sized accordingly.

When considering the scope of the metric, it is important to consider the purpose of the MEAV metric in the regression modelling. Across the indirect costs (CAI & BSC), the drivers of our spend are different for the two different types of spend.

- Project Specific ("capex") spend – exclusive to CAIs. This is wholly driven by the associated capex spend and therefore capex is the appropriate driver to be used in the modelling
- Non-project specific ("opex") spend – across CAIs and BSCs. These costs have a mix of drivers, including the size and complexity of the organisation, the number of people in the organisation and the amount of work (capex) being delivered, as well as having an underlying fixed cost element. As a result, MEAV and FTE have been used in the modelling to supplement the underlying capex driver that otherwise would not appropriately consider these non-project specific costs.

The excluded T2/T3 crossover projects will still contribute assets, FTEs and workload that the organisation is scaled to deliver and support, irrespective of Ofgem's choice of mechanism to fund them. These projects therefore contribute to the non-project specific costs that are being assessed, and it is incorrect to exclude them from the driver that forms the other half of the calculation. In Final Determinations, Ofgem should revert to the previous method of calculating asset volumes based on the systems characteristics table provided as part of the Business Plan Data Tables, without these adjustments, to support the development of a more robust and reliable set of modelling to calculate the indirect allowances (this issues with which are discussed in ETQ57 and 60).

Furthermore, we are concerned that this exclusion is applied differently across the TOs, due to the way crossover projects have been reported. The following graphs show the differences in the net asset movements between the TOs at the end of the T2 period. We think these differences may be explained by a different reporting approach for projects that span the periods rather than a true view of the work being delivered. This should be investigated and resolved ahead of Final Determinations.



Our other concern is whether the MEAV calculation considers asset volumes that will be delivered by projects in the pipeline. For consistency with the cost submission, NGET's MEAV has been calculated using only assets arising from baseline projects, excluding those in the pipeline. However, from a review of data, we do not believe this to be the case consistently across TOs. As Ofgem works to develop consistent data sets for "baseline" and "best view" it is crucial to ensure that the asset volumes are appropriately updated to ensure that the drivers and costs used in regression models are well aligned. This includes ensuring consistent assumptions are made across TOs about how early-stage projects in the pipeline, which do not yet have a detailed optioneering or asset view, can be considered and incorporated into a "best view MEAV".

For Final Determination, Ofgem must:

- Address the identified issues with MEAV supporting the resolution of the consistency issues across TOs and ensuring the metric appropriately includes all assets.
- Implement our proposed corrections that will improve the robustness and reliability of the metric, leading to improvements in the Indirects models

ETQ63. Do you agree with our approach to operational training? What else should be considered within this approach?

We agree with Ofgem's approach to operational training and that these costs are not suitable for regression modelling and should be separately assessed, due to them having a different driver to the other CAI costs.

We are happy to see Ofgem's approach of reviewing both the quantitative and qualitative evidence provided by TOs to inform their decision and do not believe any changes are required.

Ofgem should maintain its current position at Final Determination.

ETQ64. Do you agree with our approach on insurance? What methodological improvements can we make?

We do not agree with Ofgem's approach on insurance on the basis that we do agree the chosen simple statistical modelling is an appropriate methodology to assess this type of spend. However, we do recognise that Ofgem's approach has resulted in the right level of allowances for our forecast needs associated with baseline spend.

Insurance costs are driven by the number, size and mix of assets to be insured as well as the external market variables of price, supply and demand, over which TOs have no control. We agree with Ofgem's approach to consider only the RIIO-T3 forecast insurance costs in the modelling; an approach which recognises the evidence provided by the TOs on changes to the external insurance market between price control periods and the impact this has on insurance costs.

However, we do not believe a simple ratio model to a network length driver appropriately considers, for instance, the significant difference in insurance costs between onshore and offshore assets. This is largely due to the offshore assets being more challenging and costly to repair and replace if they were to fail, therefore increasing insurers' risk exposure.

Whilst we understand that Ofgem has tested some models using an onshore / offshore split and/or MEAV (which gives some consideration to different asset types), these models are likely to have been affected by the data consistency issues discussed in depth in ETQs 57 & 60 and therefore should not be relied upon. Should Ofgem determine that it has been able to gather consistent data via the additional SQs, then this could be used to re-run the analysis. Alternatively, Ofgem could retain the approach used across the other investment types that where market tested evidence is provided, a limited further review is required.

For Final Determinations, Ofgem should base their assessment on the detailed, market tendered evidence provided by TOs and only move to a statistical modelling approach if there is certainty that the model can appropriately and robustly account for the different costs associated with different types of assets.

ETQ65. Do you agree with our approach to pension scheme admin and PPF levy? What else should be considered within this approach?

We agree with Ofgem's approach to pension scheme admin and PPF levy.

Due to the differences across the TOs, it is appropriate for this line to be removed from regression modelling and assessed separately assessed. There is nothing further that Ofgem needs to consider.

Ofgem should maintain its current position at Final Determination.

ETQ66. Do you agree with our assessment approach for Physical Security? If not, how should we assess these costs?

We do not agree with Ofgem's current approach to consider the lower of RIIO-ET2 and ET3 unit costs, however we do consider that a quantitative assessment approach could be appropriate for Physical Security.

The security landscape continues to evolve and our approach to security must continue to develop to react to the increasing threat level, in line with Government best practice and industry standards. This security requirement drives additional cost into the ongoing operating (opex) costs in particular and therefore we disagree with the statement that "*generally, RIIO-ET2 unit costs are reflective of RIIO-ET3 unit costs*".

TOs face additional identified risks from potential sabotage by national actors, including recent activity attributed to Russia across Europe, and the associated increase in the perceived risk of such events affecting UK infrastructure. Physical security services also support the management of risks related to environmental activism, as there is an assessed substantial likelihood that National Grid may be targeted through protest activities or similar actions. Furthermore, NGET has transitioned to holistic threat management, with supplementary services establishing a vital source of information that supports both the ISS and non-ISS estates.

At Final Determination Ofgem should adopt an assessment approach that gives due consideration to the forecast costs to deliver rather than a reliance on backward looking unit costs, recognising that the security threats faced and therefore the cost to delivery Physical Security do change over time.

ETQ67. Do you have any views on our engineering assessment of the thematic issues we have identified?

We agree that the list of four points in paras 5.172-5.186 of the ET Sector Annex are significant themes within the electricity transmission sector, and provide views on three of the four themes:

- Non-Load Related Expenditure
- Load Related Expenditure
- Use of GIS

Please see also our response to NGETQ10 that provides detailed information to respond to the specific points raised by Ofgem relating to the engineering assessment of our submission, which includes several of the themes within this question.

Non-Load Related Expenditure

Ofgem raises three themes relating to non-load related expenditure:

- a) links to previous approaches and risks of double funding,
- b) our requests for funding to replace assets with a relatively good asset health scores, and
- c) the deliverability of our baseline asks.

a) Links to previous approaches and risks of double funding

We are committed to working transparently and are concerned that Ofgem considers there has been a lack of clarity around our previous investment strategies.

We do not consider there is a risk of “*potential double funding of investments*” in the RIIO-T3 period. Protections are already in place through Price Control Deliverables for any interventions not completed in the T2 period, which means any allowances for work not completed are returned to consumers. We continue to report regularly on progress towards delivery of RIIO-2 interventions via RRP at both project/portfolio and asset-specific levels. Our RIIO-T3 Portfolio EJPs show where all assets replacements have taken place.

Previous price controls worked differently from the approach implemented for RIIO-2. TPCR4 and RIIO-1 expressed funding in high-level financial terms (allowances being provided by Ofgem at asset category level) and set Outputs in terms of network risk and reliability rather than a count of interventions or named assets. As RIIO-T1 was not a ‘named asset replacement’ framework, networks had the ability to re-prioritise and optimise its replacement plans, including replacing assets at different locations to achieve the same or better network risk outcome for customers and consumers. The outcome of this was assessed extensively by Ofgem as part of the NOMs/NARM close-out process, and Ofgem concluded in its RIIO-1 NOMs Closeout Draft Determinations that NGET had over-delivered against the incentive mechanism by 31%²⁴.

If there is specific further information which Ofgem would find helpful, we would be happy to discuss this. We are committed to helping Ofgem understand our asset management activities, including through the quarterly delivery update meetings we established last year to share information and discuss our delivery of the entire RIIO-T3 deal.

b) Asset health scores

Ofgem raises the concern that it has been unable to consistently see the relationship between asset condition data and the economic case for intervention on assets. We have made some changes to our plan in line with the way suggested by Ofgem, we have not changed the position in every case, because we believe there are broader reasons beyond asset health for considering whether assets should be replaced as part of a comprehensive asset management strategy. Our answer to NGETQ8 provides a comprehensive response to the triggers used to build our baseline and pipeline plan for asset health.

Good asset management practice seeks to provide value by balancing the drivers of cost, performance and risk. Replacement decisions must account for additional factors such as impact of failure, obsolescence, safety/legal/regulatory compliance, performance, environmental factors and operating cost, as well as health (the probability of failure). Our asset management strategy follows good asset management practice and was used as the basis of the investments in our plan.

²⁴ [Consultation](#), page 26.

c) Deliverability

We share Ofgem's focus, as noted in the last sentence of paragraph 5.177, that deliverability is an important issue and we are realistic about the challenges we face today. In section 1.6 of our business plan, we set out the four types of delivery constraint we considered (system access, supply chain, workforce and skills, and community acceptance), the actions we are taking, and the support we need from others to achieve the energy transition for the benefit of consumers.

Throughout RIIO-T2 we have achieved an 8.5% year on year growth in the number of asset health interventions, delivering more last year than at any point. This is putting us on the right trajectory to deliver our non-load plan in RIIO-T3

A flexible reopener framework for non-load interventions would improve the deliverability of our non-load investments and supports us to maintain a resilient network. It would allow us to re-prioritise asset replacement candidates to take advantage of delivery opportunities and respond to changing drivers (e.g. customer-driven changes) is essential to support the asset health programme, and should provide the clarity and confidence necessary for rapid decision-making.

Load Related Expenditure

We agree with Ofgem's view that there are clear needs cases for our load related investments, and their observation that there is increasing overlap between load and non-load drivers. This is a feature of the rapid expansion of the existing integrated transmission system in England and Wales at the same time as the need to intervene on infrastructure which has been in place for decades given the timing of the last significant expansion of the network. For example, 70% of our non-load drivers on overhead line investments will be met through interventions to meet load drivers.

We acknowledge Ofgem's request for further clarity on such investments and have provided further information in the technical annexes submitted as part of our DD response.

Based on our analysis of all Transmission Owner business plans, NGET has the highest proportion of its load-related expenditure in the baseline. There are uncertainties due to factors not wholly within our control, such as Connections Reform, which will affect what load investments progress and as such has interactions with our non-load plan. Ofgem's framework provides flexibility to manage such uncertainties, which have used to inform our decisions on whether to include investments in the pipeline or baseline, taking into account Ofgem's guidance.

Use of gas insulated switchgear (GIS)

We agree that GIS, where clearly articulated and evidenced, is a well-justified technical solution. Any technical solution (including AIS) has advantages and disadvantages which need to be clearly articulated, evidenced and assessed against an agreed and consistent framework.

From a GIS perspective, our business plan submission has been developed to select the most appropriate solutions to balance the multiple (sometime conflicting) drivers we face. While we recognise the advantages of AIS from a techno-economic perspective, our experience is that when the advantages and disadvantages are fully assessed, the decisions on which technology is most appropriate in the circumstances is often a finely balanced judgement. We do not agree that *"AIS appears to have a greater long-term potential for continued use"* (ET Annex para 5.184).

There are multiple factors that should be considered, including those around extendibility, OEM relationships and the use of F-gases identified by Ofgem, but other factors (including land requirements, planning and consenting risks, stakeholder acceptance and a broader assessment of environmental issues beyond F-gases) are relevant. These must also be included in the project optioneering process.

Our answer to ETQ69 (and the associated attachment) sets out our main response to this theme. Our responses to ETQ68 (use of extendible designs) and NGETQ9 (optioneering assessments considering asset health and GIS use in site strategies) also cover related points. In NGETQ10 we provide information on the choices specific to each site where Ofgem has raised questions about our selection of switchgear.

Not all factors could be quantified consistently and therefore we have considered some factors qualitatively reasons such as land-take, deliverability, stakeholder acceptance and environmental considerations – we understand that these have been more challenging for Ofgem to assess and therefore are keen to work with Ofgem between now and Final Determinations to develop a consistent industry assessment approach.

Acknowledging Ofgem's position that we could enhance our optioneering analysis further, we set out within 'NGET_RIIIO3_NGETQ9_ETQ68_ETQ_69_'AIS GIS approach to quantification' the following:

1. Further clarification on our approach to AIS/GIS selection and how these were applied to individual EJPs (we seek to address this further through specific project responses in NGETQ10),
2. Explanation of the local constraints (planning, stakeholder acceptance) and environmental considerations we must also take into account and how this shapes our choice in technology, and
3. Our proposal for a “Balanced Scorecard” to drive consistency on optioneering and underlying assumptions.

Our view is that, in order to drive consistency in decision-making across the industry, reduce the regulatory burden, and ultimately accelerate the development of future pipeline works, a common, agreed approach to scoring the relative merits of an AIS or GIS solution is needed. If agreed before RIIO-T3 and applied effectively, this approach would remove the need for extended optioneering debates, support a ‘workable framework’ and improve deliverability of CP2030 plans.

Our proposed Balanced Scorecard approach seeks industry alignment on a set of key factors in AIS/GIS decision making which can be consistently assessed on both a qualitative and quantitative basis. By aligning as an industry on the relative importance of some factors over others, as well as the quantification parameters up-front we can streamline regulatory processes, provide transparency and comparability into RIIO-3 thereby ‘fixing forward’.

It will not always be possible to apply new policies to “in-flight” projects which have already been developed under a different set of policies and contexts. New policies need to be applied on a prospective basis only, unless they can be accommodated in in-flight projects without a material cost of scheduling impact, either of which will ultimately create consumer detriment.

To ensure that TOs can operate at pace, and with confidence that funding will be forthcoming, Ofgem must:

- **develop and consult on a clear set of policies for project optioneering (including AIS/GIS), which cover all engineering and other factors, to provide consistency and speed into future optioneering processes on a ‘fix forward’ basis. To not do so would be a clear procedural failure and a breach of Ofgem’s statutory duties;**
- **Recognise that new policies cannot be applied retrospectively to ‘in-flight’ projects without causing significant schedule or cost implications that would impact customers, consumers and wider stakeholder objectives such as CP2030 and other national ambitions. Instead, Ofgem must work with Transmission Owners to reach acceptable positions for these projects, reflecting the prevailing policies and context at the time development decisions were taken.**

ETQ68. Do you agree with our approach to maintaining future optionality through ensuring licensees use extendible designs?

We agree with the principle of maintaining future optionality through extendible designs. However, we do not agree with the approach outlined to ensure licensees use extendible designs. While this is an important requirement which we seek to include in our designs, it may not always be the best value option for consumers, which is the implication of ensure.

Extendibility is one of several considerations that need to be considered in the project optioneering process. Other factors like land-take, deliverability, stakeholder acceptance, environmental considerations and technical performance must also be taken into account.

Disregarding relevant considerations could result in us selecting a solution which is not in the consumer interest because it is prone to deliverability challenges, stakeholder engagement difficulties or other factors. We do not think this is Ofgem's intent, in particular in the light of the letter from Akshay Kaul's letter of 31 July 2025 to the Chief Executives of NESO and Transmission Owners in which he expressed a *"commitment to meaningful stakeholder and community engagement, alongside open and transparent consultation across NESO, the TOs, and Ofgem"*.

As described in ETQ67 and our appendix 'NGET_RII03_NGETQ9_ETQ68_ETQ_69_AIS GIS approach to quantification', we have suggested a means of consistent assessment of all relevant factors.

We do not agree that Ofgem should automatically favour AIS for extendibility reasons (ET Annex, 5.184). Extendibility is not solely a technology-based issue. Both AIS and GIS substations are modular and extendible. Contextual factors need to be considered on a site-specific basis to understand which option has the better potential for extendibility

We recognise AIS is more enabling of third party solutions, which presents advantages for extendibility. However, the larger footprint has disadvantages from an extendibility perspective in areas where land is constrained or where there are planning issues or local stakeholder acceptance, e.g. in green belt locations. As such, in some circumstances GIS has extendibility advantages over AIS. For example, a Friston by changing our technology choice from AIS to GIS we were able to extend the design without causing a delay to the project as the extended substation – for future customers – will fit within the existing footprint, the basis of which was used to secure planning permission.

Ofgem must:

- **develop and consult on a clear set of policies for project optioneering (including AIS/GIS), which cover all engineering and other factors, to provide consistency and speed into future optioneering processes on a 'fix forward' basis;**
- **Recognise that new policies cannot be applied retrospectively to 'in-flight' projects without causing significant schedule or cost implications that would impact customers, consumers and wider stakeholder objectives such as CP2030 and other national ambitions. Instead, Ofgem must work with Transmission Owners to reach acceptable positions for these projects, reflecting the prevailing policies and context at the time development decisions were taken.**

ETQ69. Do you agree with our drive to reduce the use of F-Gases as far as possible and do you agree with our intent to fast track selected AIS solutions to minimise the use of F-Gases now and in the future?

We do not agree with Ofgem's drive to reduce the use of F-Gases "as far as possible". While it is important that action is taken to reduce greenhouse gas emissions, the proposed policy of "as far as possible" does not strike the right balance, given developments in F-Gas technology significantly reduce the environmental impacts compared with SF6 technology. The proposed policy would have a net negative consumer detriment by artificially constraining the options for Transmission Owners at a time of a rapid expansion of the electricity system. It would also jeopardise Government objectives around economic growth and decarbonisation.

Modern "SF6-free" GIS technology, use gases such as C4-FN which have a 99% less carbon emission equivalence of SF6 gas. Compared to AIS alternatives, this technology has a range of benefits including its smaller footprint which has less other environmental and visual impacts compared and offers advantages in terms of land and planning requirements. These benefits have the potential to outweigh the environmental negatives from the use of an F-Gas in certain circumstances.

It is also worth noting that AIS switchgear carries small amounts of SF6 gas, where non-SF6 GIS technology relies wholly on a lesser pollutive gases. The choice of technology/solution should always be evidenced by (project-specific) cost-benefit analysis which would quantify, among other things, the comparative polluting impact of solutions and the full-life costs of different technology choices.

We are aware of EU legislation on F gases, this has not been enacted or proposed in national legislation. We and Ofgem must operate within the current legal and policy framework.

We do not agree with proposal to fast track selected AIS solutions "to minimize the use of F-Gases now and in the future". The environmental benefits in terms of reducing F-gases through switchgear choices need to be considered as part of a broad assessment of all relevant factors including techno-engineering, and requirements, planning and consenting risks, stakeholder acceptance and a full assessment of environmental issues beyond F-gases, taking into account the relative advantages and disadvantages of AIS and GIS options.

As described in ETQ67 and our appendix 'NGET_RII03_NGETQ9_ETQ68_ETQ_69_AIS GIS approach to quantification' we have suggested a means of consistent assessment of all relevant factors.

Ofgem must:

- **Develop and consult on a clear set of policies for project optioneering (including AIS/GIS), which cover all engineering and other factors, to provide consistency and speed into future optioneering processes on a 'fix forward' basis;**
- **Recognise that new policies cannot be applied retrospectively to 'in-flight' projects without causing significant schedule or cost implications that would impact customers, consumers and wider stakeholder objectives such as CP2030 and other national ambitions. Instead, Ofgem must work with Transmission Owners to reach acceptable positions for these projects, reflecting the prevailing policies and context at the time development decisions were taken.**

We have also proposed an alternative to the fast-track proposals for the Load Related Reopener, which would provide for more timely assessments of all Transmission Owner reopener submission, regardless of technology choice. This is discussed further in ETQ29.

Ofgem should implement the proposals set out in our Workable Framework paper, as an alternative to framework set out in the Draft Determination

We provide further detail on our position below covering the following points which relate to the proposal for applying "fast-tracking" on the basis of technology choice:

- A collaborative, transparent optioneering framework —co-developed by Ofgem and TOs— would be more effective than fast-tracking;
- Ofgem's PASE proposals overlap with, and may contradict, the Electricity Transmission Design Principles (ETDP) project led by NESO, which needs to be resolved to avoid confusion and ambiguity;
- Ofgem appears to be applying a de-facto policy before appropriately consulting with key stakeholders which is a clear procedural failure;
- Ofgem's presumption in favour of specific technology choices must be considered in the context of our obligations under primary legislation, in particular Section 9 of the Electricity Act 1989 (as amended); and

- Ofgem's drive to reduce F-gases should be part of a wider suite of policies (appropriately consulted on) through which Ofgem will enact its net zero, and other, duties

Accurately and transparently recording the optioneering framework – co-developed by Ofgem and TOs would be more effective

Our view is that to drive consistency in decision-making across the industry, reduce the regulatory burden, and ultimately accelerate the development of future pipeline works, a common, agreed approach to scoring the relative merits of an AIS or GIS solution is needed. If agreed before T3 and applied effectively, this approach would remove the need for extended optioneering debates, support a 'workable framework' and improve deliverability of CP2030 plans.

Our proposed Balanced Scorecard approach (see 'NGET_RII03_NGETQ9_ETQ68_ETQ_69_AIS GIS approach to quantification') seeks industry alignment on a set of key factors in AIS/GIS decision making which can be consistently assessed on both a qualitative and quantitative basis. By aligning as an industry on the relative importance of some factors over others, as well as the quantification parameters up-front we can streamline regulatory processes, provide transparency and comparability into RII0-3 thereby 'fixing forward'.

Combined with our proposed changes to the load related reopener (see question ETQ29), to introduce fixed timetables for Ofgem determinations and the joint-management of the pipeline of submissions, supported by Director-level Ofgem governance, this would be a more effective way of accelerating Ofgem determinations whilst ensuring all relevant factors are taken into consideration. Fast tracking of the load related reopener would not be required.

Establishing key principles in the Balanced Scorecard (see 'NGET_RII03_NGETQ9_ETQ68_ETQ_69_AIS GIS approach to quantification') would be the first step to ensuring transparency and consistency for how AIS/GIS options should be assessed in T3. Once agreed between industry and Ofgem these principles should be consulted upon to ensure the range of community and wider interests are considered and then applied gradually in a way that matches the development timescales of our projects, avoiding negative impacts on Clean Power 2030 and other national ambitions.

It will not always be possible to apply new policies to "in-flight" projects which have already been developed under a different set of policies and contexts. New policies need to be applied on a prospective basis only, unless they can be accommodated in in-flight projects without a material cost of scheduling impact, either of which will ultimately create consumer detriment.

Ofgem's PASE proposals overlap with, and may contradict, the Electricity Transmission Design Principles (ETDP) project led by NESO

We understand Ofgem's proposals concerning 'fast tracking' are intended to apply both where the ETDP are followed (ET Annex, 5.170) and where the Pre-Approval of Solution by Engineering (PASE) is applied (ET Annex, 4.68). While we are supportive of initiatives aimed at streamlining regulatory processes, we are concerned that PASE's emphasis on an AIS output risks unintended consequences in terms of how it incentivises Transmission Owners (TOs).

Our interpretation is that PASE is designed to encourage TOs to select the "least contentious" solution with regard to regulatory approval—such as AIS—to expedite allowances, even when GIS might be more suitable when taking into account environment, community and wider social economic impacts. We do not support PASE as the criteria for fast tracking, because technology choices must be tailored to the requirements of each project, rather than being inappropriately influenced primarily by opportunities to reduce regulatory burden. The proposed reduction in optioneering appraisal (ET Annex, 4.71), based on unsubstantiated assertions of improved whole life costs and the adaptability of PASE-compliant projects, is not the correct way to make engineering choices that are in the best interests of consumers and communities hosting national infrastructure.

This approach could lead to jeopardizing timely delivery of critical infrastructure through consenting risks, heightened stakeholder opposition, and escalated project costs to consumers — outcomes contrary to PASE's intent but also the pace of infrastructure development required into the future. Additionally, it remains uncertain whether Ofgem would hold TOs responsible for such delays if the chosen substation design complied with PASE, and will run counter to the intent of delivery and customer incentives Ofgem is proposing elsewhere as part of the framework.

We support ETDP as a guidance framework to provide greater clarity on the type of asset to be used in different environments, noting that this was a recommendation within the Transmission Acceleration Action Plan²⁵. We are continuing to collaborate with NESO on the draft ETDP, and we await Ofgem's re-opener guidance corresponding to these principles (ET Annex, 5.17/0).

It is not clear how PASE and ETDP will interact. While PASE prescribes AIS and specific substation configurations,

²⁵ <https://assets.publishing.service.gov.uk/media/65646bd31fd90c0013ac3bd8/transmission-acceleration-action-plan.pdf>

the ETDP are intended to provide a guidance framework for TOs developing infrastructure investments. It is unclear whether the application of the ETDP or PASE would take precedence for Ofgem's consideration of reopener submissions, if, for example, applying the ETDP resulted in a GIS outcome.

As described in question ETQ29, we have proposed an alternative way which we consider better meets the objective of streamlining the reopener process and influencing TO optioneering decisions, including through fixed timetable and stronger governance.

Ofgem appears to be applying a de-facto policy before appropriately consulting with key stakeholders which is a clear procedural failure

Ofgem has not previously consulted on its apparent presumption in favour of AIS technology in advance of the positions now set out in both the 2025 MSIP Draft Determinations and in the RIIO-T3 Draft Determinations. This is a clear procedural failure. It is therefore essential that Ofgem engages with and consults TOs and other stakeholders on its proposals and conscientiously takes the product of that consultation into account ahead of Final Determinations. This would match the 'fix forward' plans agreed between senior Ofgem and NGET officials for RIIO-T3, but would not resolve our 'in-flight' portfolio of projects including the MSIPs. For these, we look forward to the conclusions of the NGET/Ofgem steering groups to mitigate significant schedule or cost implications impacting customers, consumers and wider stakeholder objectives

In keeping with policy best practice and Ofgem's statutory duties Ofgem must appropriately consult with the full range of relevant national, local and environmental stakeholders to ensure the range of community and other perspectives is taken into account. A transition to such policies is needed given the development timescales of electricity transmission projects. This includes finding a way to progress projects where there are disagreements on optioneering, but where new policies cannot be applied retrospectively to an in-flight project without causing significant schedule or cost impact that would impact customers, consumers and wider stakeholders.

Ofgem's presumption in favour of specific technology choices must be considered in the context of our obligations under primary legislation, namely Section 9(1) of the Electricity Act 1989 which places an obligation on transmission licensees to "*develop and maintain an efficient, co-ordinated, and economical system of electricity transmission*". The deployment of AIS solutions in some instances may be contrary to this obligation and these issues need to be fully considered through the appropriate consultation process that we refer to above. It is not appropriate for an economic regulator to prescribe specific engineering outputs for TOs or to introduce implicit incentives that affect technology selection that could be counter to our statutory duties under primary legislation.

Ofgem's drive to reduce F-gases should be part of a wider suite of policies through which Ofgem will enact its net zero, and other, Government aspirations such as SF6 free innovation

Whilst we agree in principle with the objective of minimising the use of polluting gases, this should be part of a holistic package of policies that will enact Ofgem's net zero duty and balance this duty with Ofgem's other duties including, for example, to protect the interests of existing and future energy consumers, and Ofgem's economic growth duty.

On the latter, it is unclear how PASE's incentivisation of AIS, will support the stimulation of the market and supply chains toward innovative SF6 free solutions, which the Government identifies as a key opportunity for the UK for economic growth:

*"Exploring routes to drive forward the phase out of SF6 gas from switchgear in electricity network infrastructure, to help UK manufacturers to capture an emerging market and capitalise on the UK's position at the forefront of developing SF6 switchgear alternatives. The Government will look to align with the EU process where appropriate"*²⁶.

Engineering choices are not made in isolation. The choice of gas-insulated or air-insulated switchgear has cost implications for consumers and implications on the speed with which we can deliver the projects that connect new sources of low-carbon generation, as well as new data centres and gigafactories that drive economic growth.

F-gases are not the only greenhouse gases that need to be managed to achieve net zero. Ofgem should set out how it intends to achieve its net zero duty overall, considering the roles that F-gases play alongside, for example, reducing emissions across the rest of the economy through greater electrification and connecting low carbon generation.

We are already undertaking a suite of measures to manage emissions from F-gases, and other environmental impacts. Our RIIO-T3 business plan set out our objective to play a leading role in accelerating net zero and driving a nature positive future, including by reducing our own emissions and environmental impact. We set out our

²⁶ [Industrial Strategy: Clean Energy Industries Sector Plan](#)

commitments to drive sustainable operations through reductions of SF6 emissions (SF6 is an F-gas), reduce energy use in our operational estate, and in fleet vehicle emissions. Further details can be found in our Environmental Action Plan submitted as an annex to our business plan submission in December 2024²⁷.

²⁷ <https://www.rii3.nationalgrid.com/document/30008/download>

ETQ70. Do you agree that the TIM in RIIO-ET3 should have a primary focus on risk management and a secondary focus on cost efficiency, and that doing so would be in the interests of consumers?

We agree with Ofgem's underlying principle that TIM should provide a focus on both cost efficiency and risk management. We do not agree that the proposed primary focus remains consistent when considering the diverse portfolio within our RIIO-T3 regulatory period. The primary focus should vary when applied to the differing elements of our Totex portfolio.

Our RIIO-T3 portfolio contains activities ranging from major projects to repeatable, lower risk activities.

- Nearly 60% of our RIIO-T3 investment is represented by ASTI, CSNP and Load Related major projects. These projects are significant in scale, both in terms of level of investment and project duration, are at varying stages of development and subject to significant risk of cost overruns due to the scale of these projects, wider economic factors, supply chain constraints and planning delays. The risk profile for offshore projects within this category is significantly different, given the impact of "seasons" when offshore work can be conducted safely.
- The remaining 40% of our portfolio is attributable to repeatable activity where we have a greater level of control over the delivery of the investment.

We agree that for large, complex, projects with high-cost uncertainty, where the primary consumer interest is in the timely delivery of the outputs, the primary focus of TIM should be on risk management with a secondary focus on cost efficiency.

For business-as-usual activities where the consumer's interest is the delivery of the service at the lowest possible cost, and cost control is more broadly within the TO's direct influence, a stronger and more consistent cost efficiency incentive remains critical.

At Final Determination, Ofgem must:

- **Maintain a primary focus on risk management for major projects while allowing for a stronger emphasis on cost efficiency for business-as-usual activities.**
- **Retain existing regulatory mechanisms and implement the PCD funding adjustment mechanism on ASTI projects, to protect consumers from cost uncertainties arising from major capital projects.**
- **Avoid a weaker TIM incentive as a 'catch-all' reason to place less emphasis on the importance of setting the price control totex allowances at a level that allows networks to finance and deliver the necessary investment in infrastructure to maintain and upgrade the energy network.**

We are concerned to note references²⁸ within DDQ responses and ET Annex suggesting that Ofgem considers TIM as a funding mechanism to be used to cover low materiality unplanned interventions. TIM is an incentive not a funding mechanism.

We recognise that the growth in investment levels in RIIO-T3 and the changing nature of the investment portfolio is creating a challenge for the framework, and so TIM has a greater role in providing protection of last resort for consumers and networks. However, in doing so, it does not diminish the importance of creating an underlying framework that seeks to provide efficient allowances for the required investment.

Focus on Risk Management for large, complex projects

Ofgem's proposal does not fully achieve the stated intention of focusing on risk management. The uniform approach to application is not appropriately targeted at the areas of the cost base where risk management is most required and is most valuable for consumers – ASTI and other major projects with similar risk profile where timeliness of delivery provides a meaningful consumer benefit. Insulating TOs from a greater proportion of overspends will help incentivise the focus on timely delivery.

ASTI²⁹ was introduced in August 2022 as a response to the strong consumer interest in reducing time taken to connect renewable generation and addressing any resulting boundary transfer capabilities. For NGET, it covers seventeen on- and off-shore "megaprojects", which together comprise the biggest expansion in the electricity network in a generation. Given the scale of these projects, the associated risk profile of such large scale construction and the materiality of cost overruns are all different when compared to recent work on the electricity transmission system

As such, the ASTI document proposed a step change in the way large onshore transmission projects are planned, consented, contracted and delivered. To support this, Ofgem proposed changes to the existing regulatory framework to make it more agile, responsive and flexible, whilst still maintaining measures to protect consumers from unnecessary or excessive costs.

²⁸ ET Annex – 4.86, ET Annex – 5.37, DDQ075

²⁹ [Accelerating onshore electricity transmission investment](#)

Ofgem recognised that there is an increased risk of windfall gains or exposure to unfunded costs for TOs arising from the greater cost uncertainty than has typically been seen for projects delivered through the Large Onshore Transmission Investment (LOTI) regulatory framework. This risk is driven by external factors such as a constrained supply chain, commodity and labour price volatility, and the requirement for new assessment approaches to streamline the regulatory assessment process.

To mitigate this, Ofgem consulted on an amendment to the PCD mechanism that would introduce an allowance adjustment on completion of the project to limit performance to +/-5% of allowances. This would provide protection for both consumers and TOs from any windfall gains or exposure to unfunded costs. The proposal has been subject to a published decision and consultation on licence amendments³⁰ in 2024, but it has not yet been enacted within the licences for any TOs.

Coupled with the ASTI Delivery Incentive to encourage accelerated completion of crucial upgrades, this PCD mechanism, along with output adjusting mechanisms, provides suitable protection from the cost uncertainty associated with these projects as previously recognised by Ofgem.

We see no reason for this to change, particularly when the decision to implement it was made so recently. Ofgem's existing approach outlined by the ASTI PCD provides a more effective, comprehensive and targeted 'risk management' approach - with protection for consumers and networks targeted at the areas with material cost uncertainty.

In DD, Ofgem has proposed the CSNP delivery incentive to encourage the timely delivery of infrastructure to ensure consumers realise benefits as early as possible to support delivery of the UK's decarbonization targets. This regime has also been proposed to be applied to other non-CSNP projects on a case-by-case basis. We would also propose that the PCD mechanism would also be effective when applied to specific major projects that drive consumer value from their timely delivery.

Focus on Cost Efficiency for repeatable investments

The proposed TIM design reduces the strength of efficiency incentives for delivery of the 40% of portfolio comprising repeatable activities:

- Ofgem's Draft Determinations TIM would reduce the RIIO-T2 TIM rate (i.e. the share of any outperformance/underperformance that is retained by the TO) from 33% to 25%.
- the TIM rate would fall further to 5% if our spending is above or below allowances by at least 5%; and
- it reduces further to 0% beyond a cap/collar of 15% over- or under-spend.

Lower sharing rates discourage efforts to pursue incremental cost savings in these areas - resulting in lost opportunities for consumers to benefit from revealed efficiencies and innovation both in the short-term and over time.

Without retaining the RIIO-T2 approach, a 10% overspend on major projects would wipe out any efficiencies achieved in repeatable investment and there would be no efficiency incentive remaining as networks would be at the collar.

This introduces greater uncertainty and it dampens the effectiveness of the incentive to drive for efficiency throughout the period.

Being applied on an annual basis, the proposed design creates a perverse incentive where networks are approaching or exceeding thresholds in a single year as outlined in our response to ETQ71.

As a network approaches the boundary, the incentive to drive efficiency is reduced or removed. This is exacerbated by the inclusion of ASTI projects within the calculation. Major projects of the scale represented by ASTI, and the early stages of maturity are more likely to be exposed to greater cost volatility across years, triggering movement between the incentive step levels caused by the ASTI portfolio alone. This will have the unintended consequence of removing or reducing the strength of incentive provided by TIM for the remaining portfolio.

Differing TIM treatments across the price control

In Draft Determinations, Ofgem raised concerns around gaming risk potentially created by having differing TIM treatments within the price control. However, we consider any such risks are (or can readily be) well mitigated.

First, RIIO-T2 precedent demonstrates that differing TIM rates for ASTI projects vs RIIO-2 Totex already operate effectively under appropriate controls. Ofgem has already implemented differential TIM treatment and to our knowledge has found no concerns with costs being 'artificially moved' between ASTI and RIIO-2.

Second, if Ofgem's concern is that a TO might adopt different 'on the ground' spending and change the delivery of

³⁰ [Consultation SpC 9.3 PCD Guidance Final](#)

physical infrastructure due to an incentive distortion from TIM, there are a substantial number of protections already in place against this. Large, major works cannot simply be not delivered or substituted with BAU works. Physical delivery of infrastructure that is funded under BAU is constrained by PCDs, licence obligations, and engineering schedules. In practice we see no meaningful risk of this type of distortion arising.

Third, if Ofgem's concern is that accounting cost allocation is at issue, there are many protections in place. Misclassification of costs would constitute a licence breach and is already subject to established assurance processes, including regulatory reporting, audit trails, and Board-level accountability. We would also welcome discussion of any additional safeguards Ofgem would like to see put in place – for example, continued 'forensic audits' on major works projects like those undertaken in annual cost visits, to ensure that cost reporting and allocation has been transparent and reflective.

Even if Ofgem has any residual concerns, despite these mitigating features, for the Final Determinations Ofgem must properly weigh up any downside risks it may perceive of alternative TIM approaches, as compared to the pros / cons of its Draft Determinations proposal.

ETQ71. Do you agree with our proposed 'stepped' design of the RIIO-ET3 TIM, including the values that we have used to set each 'step'?

We do not agree with Ofgem's proposed "stepped" design of the TIM. Compared to an alternative design, it would increase regulatory burdens, create inconsistent and unjustified outcomes through the application on an annual basis and create unintended consequences from having varying rates during the price control period.

We are concerned about the practical application of the proposed 'stepped' TIM design and the regulatory complexity it may introduce. These issues could be tackled through introducing a simplified design of the TIM, with a single broader band (<10% over/underspend at 25% sharing factor) combined with a cap/collar 10%. This would maintain the balance between focusing on cost efficiency and risk management. This design would remove the complications of moving between bands within the proposed design and give TOs greater certainty to drive efficiency for consumers.

It has the following advantages over Ofgem's proposal:

- reducing regulatory burdens;
- avoiding illogical outcomes arising from the application on an annual basis;
- removing unintended consequences created from having varying rates within the price control period.

As explained in our response to ETQ70, the effectiveness of stepped TIM in supporting the delivery of consumer interests will be further enhanced by retaining the existing risk management measures introduced alongside ASTI and applying these to major projects where consumer interests are best served by timely delivery.

Ofgem should introduce a streamlined version of the TIM framework by maintaining a single sharing factor combined with a cap/collar. The sharing factor should be set at 25% and the cap/collar at 10%. The TIM should be applied on the basis of forecast performance with an end-of-period true up.

Ofgem must also maintain existing RIIO-T2 risk management mechanisms, as outlined in our response to ETQ70, to operate alongside the streamlined TIM.

As discussed in ETQ70, it should be combined with existing risk management measures for ASTI projects and other major projects with a similar risk profile.

We would welcome working-level sessions with Ofgem and the other TOs to further develop the framework to ensure the appropriate balance between risk management and cost efficiency is retained whilst removing any unforeseen downsides associated with the mechanism.

Increased regulatory burden

The complexity of operating a stepped TIM design with 3 bands, +/- 5%, +/- 5-15%, and >15% with differential sharing factors increases the regulatory burden for both Ofgem and TOs with greater reporting required to ensure that TIM is being applied correctly. We feel this will lead to more complex annual iteration processes when setting revenues to ensure that the bandings are being appropriately applied.

The application of the 3 bands also creates uncertainty for TOs when giving investment analysts a view of the TOs expected results and forecast. This will undermine the levels of investor confidence at a time when there is a need to attract significant investment into the sector.

This issue could be resolved with a simplification of the proposed design and implement a single band design for TIM. We propose that the first band proposed by Ofgem is expanded to +/- 10%, and no sharing for over/under-spend beyond the 10%.

Whilst this reduces the performable bands from 15% to 10%, by maintaining the sharing factor at 25%, it presents a slightly stronger incentive on efficiency.

This simpler approach would be easier for Ofgem to operate and sends clearer incentive signals on efficiency.

Illogical outcomes arising from the application of caps and collars on an annual basis

In Draft Determinations, Ofgem has proposed that the sharing factor will be calculated on an annual basis. In certain circumstances this can create an illogical outcome by providing an overall reward or penalty for consumers and networks, when neither is justified when looking at the full cost of the project. The table below illustrates this through a notional example.

In the example, we assume that T3 total overspend / underspend is zero over the price control as a whole, but that within years there is variation in overspend/underspend, (specifically, we assume underperformance in Yr1 by 40% and then 10% outperformance in the remaining four years of the price control). By applying the proposed TIM stepped

design annually NGET would receive an upside (in this illustration, upside of £42.5) funded by customers.

	Yr1	Yr2	Yr3	Yr4	Yr5	T3 Total
Allowances	1000.0	1000.0	1000.0	1000.0	1000.0	5,000.0
Totex	1400.0	900.0	900.0	900.0	900.0	5,000.0
Performance in year	-400.0	100.0	100.0	100.0	100.0	0.0
NGET TIM share	-17.5	15.0	15.0	15.0	15.0	42.5
Consumer TIM share	-382.5	85.0	85.0	85.0	85.0	-42.5

We do not believe this is the intended outcome, as logic would dictate a neutral outcome for both consumers and TOs.

We then modelled the same example, calculating the sharing factor based on a cumulative view of performance across the price control period.

	Yr1	Yr2	Yr3	Yr4	Yr5	T3 Total
Allowances	1000.0	1000.0	1000.0	1000.0	1000.0	5,000.0
Totex	1400.0	900.0	900.0	900.0	900.0	5,000.0
Performance	-400.0	100.0	100.0	100.0	100.0	-
NGET TIM share	-17.5	17.5	13.3	25.0	25.0	63.3
Consumer TIM share	-382.5	82.5	86.7	75.0	75.0	-63.3

Again, this did not produce the intended outcome, with an even greater share of performance generated for NGET.

To resolve this anomaly, we would propose that TIM is applied based on the forecast view of overall performance outturn when considering the full price control period. We have illustrated this in the table below:

	Yr1	Yr2	Yr3	Yr4	Yr5	T3 Total
Allowances	1000.0	1000.0	1000.0	1000.0	1000.0	5,000.0
Totex	1400.0	900.0	900.0	900.0	900.0	5,000.0
Performance	-400.0	100.0	100.0	100.0	100.0	-
Cumulative performance	-400.0	-300.0	-200.0	-100.0	0.0	-
NGET TIM share	-100.0	25.0	25.0	25.0	25.0	-
Consumer TIM share	-300.0	75.0	75.0	75.0	75.0	-

We recognise that during the period, this may be subject to under and over estimation of the performance outcome and so would recommend that an aggregate true up of the price control period is undertaken as part of the close out of RIIO-3, to ensure consumers and TOs do not benefit from windfall gains or losses arising from forecast differences.

Unintended consequences from having varying rates within the price control period

Ofgem has designed the stepped TIM mechanism to provide an incentive with varying strength depending on the level of over/under performance experienced by the network company. The mechanism is applied annually creating the scenario where a network may move from a position of a strong incentive arising from overperformance in one year to a strong protection position from underperformance in the following year, as illustrated in the examples above.

Once the upper incentive threshold is reached, the incentive for the network to continue to seek additional efficiencies in a single year is removed. Similarly, there is a reduced incentive for a network to pass beyond the upper threshold of the strong incentive. In the current design as proposed, networks will benefit from delaying efficiencies into future years where they are in the strong incentive band.

Similarly, networks do not benefit from seeking additional efficiencies once their performance in a year has passed in the lower thresholds. We do not believe this is in consumers best interests and will generate additional regulatory burden to ensure that reporting is in place to manage this risk.

ETQ72. Do you agree with our proposal to include ASTI within this TIM approach?

We do not agree with the proposal to include ASTI within the proposed TIM approach. As discussed in ETQ70, the existing arrangements for risk management should continue for ASTI and other major projects with similar risk profile where timeliness of delivery provides a meaningful consumer benefit.

The TIM proposal would change the balance between timely delivery and cost efficiency which is critical in the delivery of major projects in consumer interests like ASTI.

The proposal is also inconsistent with the introduction of the ASTI PCD funding adjustment mechanism (set out in Ofgem's August 2023 decision to modify TO licences to introduce the ASTI framework) that was subject to statutory consultation in August 2024. It also creates the risk of perverse incentives through the disproportionate effect of ASTI projects in the portfolio.

Ofgem must retain the established RIIO-T2 mechanisms focused on ASTI risk management for the RIIO-T3 period and introduce those additional measures that have previously been subject to statutory consultation.

We would welcome the opportunity to work with Ofgem and the TOs prior to Final Determinations in order to understand the consumer benefits of extending these mechanisms to apply to CSNP and significant investments triggered by the Load Related Reopener that deliver consumer benefits through timely delivery.

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