RIIO-T3
Draft Determination Consultation Response

Structure of this document

This document has been structured as eighteen chapters with relevant questions assigned to each chapter. Each category includes an introductory response to provide, where relevant, some overarching views in response to the Draft Determination and highlight any points that have not been addressed by the Questions posed in the consultation itself. Many of the more material concerns we have are contained within this introductory text of each chapter.

A full mapping of the location for each question is detailed in Annex 1 contained within this document. The other listed Annexes below have been issued separately

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Executive Summary

SP Energy Networks welcome Ofgem's RIIO-T3 Draft Determinations (DD) and its intention to support the Clean Power 2030 (CP2030) ambition, aligning with Ofgem's statutory duties around growth and net zero. We further recognise the substantial enhancements Ofgem has introduced in comparison to the RIIO-ET2 determination, reflecting a clear evolution in approach.

We're particularly encouraged by the positive feedback on our 'best in class' Engineering Justification Papers (EJPs). This recognition validates the strength and credibility of our technical needs cases and reinforces our commitment to transparency and rigorous planning.

Crucially, we welcome Ofgem's acknowledgement that consumer bills will need to rise in the short term to support the scale of investment required. This recognition is vital to unlocking the infrastructure needed for a resilient, low-cost, low-carbon energy system—one that is projected to ultimately reduce bills by £167 per year[1].

The finalisation and early introduction of the Advanced Procurement Mechanism (the APM)[2] ahead of RIIO-T3 is another positive step. We have already begun utilising this mechanism, which is a key enabler to provide certainty for the supply chain both before and during the price control period.

This key milestone in the RIIO-T3 price control review marks a significant shift—not just another regulatory cycle, but a transformative phase that positions RIIO-T3 as a critical enabler of the UK Government's CP2030 and net zero targets. Recognising the pivotal role our sector plays in delivering these ambitions, this response outlines the essential changes needed to make them achievable.

We are strongly aligned with Ofgem's policy intent to enable CP2030, as stated in the DD: *"RIIO-3 is our opportunity to implement a regulatory framework for energy networks that will help GB accelerate its transition to a clean power system by 2030."* However, our analysis of the DD package reveals critical funding gaps, where cuts have been made by Ofgem without any proper basis, that introduce significant uncertainty into our investment plans and risk undermining our shared CP2030 mission.

Key Areas

As we move into the final phase of the review, we believe that a successful outcome will require Ofgem to address three key areas:

1. **Investability** – Across the sector we believe that a circa £22bn equity injection will be required which is unprecedented. In order to ensure the framework supports this long-term, sustainable investment the evidence points to the need for a return in excess of 6% at 55% gearing.

2. **Cost Assessment** – We want to work with Ofgem to establish a fair and transparent approach to benchmarking costs, not an approach that results in c.60% underfunding of our indirect costs[3], the consequence of which will undermine the resources required to deliver the scale of projects, in accelerated timescales, necessary to meet CP2030 targets.

3. **Incentives and Growth Mechanisms** – Creating the right conditions to foster innovation, efficiency, and growth is essential, particularly as 86% of our expenditure is now enabled by growth mechanisms. As such, we have a critical dependency on the effective operation and administration of these mechanisms. Following Ofgem's recent decision[4] on RIIO-T2 MSIP Re-opener applications we've lost significant confidence in the application of growth mechanisms. In the immediate term, this requires the robust and accurate development of appropriate policies reflected in licence modifications, including associated guidance documents, that we must be able to endorse during both the statutory consultation and the licence amendment process. We

[1] £167 saving pa per customer where we refer to **Clean Power 2030** (in our **Business Plan** and **Finance Annex**) comes from an *assumed* saving of £4.9bn per annum among all TOs. Ofgem's cost/benefits case lacks transparency, the counterfactual may misrepresent full economic value of RIIO-T3. The longer-term whole bill benefits and the value of delivering at pace, during RIIO-3 is also not set out

[2] Electricity Transmission Advanced Procurement Mechanism | Ofgem

[3] SPT Best View forecast v ex-ante baseline allowances

[4] DD on RIIO-2 Re-opener Applications 2025: Electricity Transmission, Electricity Distribution and Gas Distribution | Ofgem

support the ambition behind the introduction of new incentive mechanisms however we remain mindful of the significant engineering effort required to define their operation and ensure their seamless integration into licence-based delivery.

These elements are fundamental to ensuring the framework is robust, fair, and capable of supporting the long-term transformation of the energy system.

Failure to address these three key areas and accurately translate them into the Licence puts at risk the transmission investment needed to accelerate delivery at the pace required. It risks slowing our investment plans that will reduce constraint costs, saving GB consumers £167 per year[5] and it risks delaying the more than 100,000 green jobs that will be created in the UK by investment in electricity transmission, adding more than £5bn[6] in UK GDP by 2030 and more than £11bn in the long term, contributing significantly towards the government's number one mission of economic growth. We do not believe this is in line with Ofgem's economic growth or net zero duties.

Ensuring an investable finance package

We welcome Ofgem's decision to enhance the financial package since the Sector Specific Methodology Decision (SSMD). This adjustment reflects a clear recognition of the heightened forward-looking risks faced by electricity transmission networks and marks a constructive step toward an investable RIIO-T3 framework.

However, to fully realise RIIO-T3's potential for customers, society, and the UK economy, further refinements are essential. In particular, the proposed return on equity falls significantly short of the level supported by robust, joint evidence from Transmission Owners (TOs). A range of cross checks and market evidence demonstrates that a Cost of Equity (CoE) exceeding 6% on a 55% gearing basis is both justified and necessary to attract sufficient investor interest as evidenced by the work undertaken by NERA[7] and Oxera[8]. Investors are currently seeing lower returns available in the ET sector compared with Gas, despite Ofgem's assertion that the sectors have similar risk. The implicit message from Ofgem is that it expects TOs to raise a greater scale and proportion of funding from investors and do so for a lower allowed return.

Without an appropriately calibrated return, Ofgem's package risks undermining the unprecedented capital mobilisation required to meet the critical CP2030 milestone, the Net Zero transition, and Ofgem's statutory growth and net zero duties. By signalling a lower return than those available in comparable international markets—where nominal equity returns of 9–10% are routine[9]—the DD may inadvertently divert capital away from UK electricity networks, delaying vital infrastructure investment which is not in line with the government's industrial growth strategy which is focused on domestic supply chains[10].

We support the introduction of a RAV-weighted Cost of Debt (CoD) mechanism and the expansion of beta comparators. However, the framework for Investability has not been sufficiently updated to reflect the significant changes in the macroeconomic environment since the last price control review, nor the vastly increased delivery requirements to meet CP2030 and Net Zero targets. To date, Ofgem has relied on established cross-checks to calibrate the CoE and assess investability, without deploying dedicated stress tests to rigorously evaluate investor appetite. Our wider set of CoE cross-checks suggests a midpoint far higher than the DD CoE. Given increased interest rates and macroeconomic conditions,

[5] £167 saving pa per customer where we refer to **Clean Power 2030** (in our **Business Plan** and **Finance Annex**) comes from an *assumed* saving of £4.9bn per annum among all TOs. Ofgem's cost/benefits case lacks transparency, the counterfactual may misrepresent full economic value of RIIO-T3. The longer-term whole bill benefits and the value of delivering at pace, during RIIO-3 is also not set out
[6] Centre for Energy Policy. (2024). *How will SP Energy Networks' RIIO-T3 investment plans impact the wider UK economy?*. Table A.7.
[7] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*
[8] Annex 2.2. Oxera. (2025*). 2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks*
[9] Annex 2.3. NERA. (2025). *2.3 2025.07.24 US Allowed Cost of Equity vs Ofgem DD*
[10] Industrial Strategy - GOV.UK (June 2025)

cross-checks which consider the debt-to-equity relationship suggest a higher CoE than Ofgem propose in its DD[11].

To compete globally for capital, strong performing UK transmission networks must offer a reasonable expectation of double-digit nominal returns and a meaningful premium over debt alternatives. As currently proposed, the DD implies investors would accept returns more than two full percentage points below those in the US—an outcome that could weaken the UK's competitive position for long-term infrastructure funding. US utilities allowed returns are around 240bps higher than Ofgem's proposed DD position on a comparable 55% gearing basis[12].

Investor perception is critical to the success of the financial package. Ofgem's RIIO-T3 investor call made clear that investors expect the same return as their 60% geared counterparts. The message received by existing and potential ET investors is that Ofgem expects TOs to raise a greater proportion of funding from equity investors, while also increasing total funding requirements—yet offering a lower allowed return. Ofgem's assertion that gas and electricity networks face similar risk is reflected in the identical beta applied to both. However, electricity transmission is assigned a lower gearing (55%), and Ofgem has discontinued the use of the flat WACC calculation – this alone contributes to a 15bp lower CoE than if Ofgem were to have retained the flat WACC methodology - making gas networks a lower risk and more attractive investment option than electricity transmission networks.

We also note an imbalance in Ofgem's treatment of equity cross-checks and the Total Market Return (TMR). By applying inconsistent quality standards to its own analyses versus those submitted by the Energy Networks Association (ENA), Ofgem has skewed its conclusions toward a lower CoE. On TMR, we support the TOs' proposal for a balanced approach with reasonable flexibility to reflect current economic realities – such as ensuring consideration of dividend growth, but also on gilt yields[13] — ensuring both stability and accuracy in estimating returns

As we approach Final Determination (FD), now is the moment for Ofgem to demonstrate its commitment to investability. A failure to rigorously test its package against a comprehensive investability framework and to increase the return on equity above 6% at 55% gearing will prompt rational investors to redirect resources elsewhere—at the expense of UK consumers, policy goals, and the broader economy.

The stakes could not be higher. Capital mobilisation under RIIO-T3 promises net-positive outcomes for bill payers, GDP growth, job creation, household incomes, and the achievement of Net Zero. We therefore urge Ofgem to provide an internationally competitive allowed return, within a financial package that enables us to maintain a Baa1/BBB+ credit rating, to attract and retain the required capital to fund the forecast investment, allowing us to deliver at pace and realise the strikingly net positive outcomes for customers and society. By doing so, we can unlock the full potential of RIIO-T3—delivering tangible benefits for customers and society.

Enabling robust cost assessment outcomes

Delivering the required investment in RIIO-T3 at pace will depend on having the necessary internal resources and skills at the right time. This means the levels of Closely Associated Indirects (CAIs) and Business Support Costs (BSCs) will be critical to success. Our indirects activities are not a consequence of our investment but drive and enable delivery. For the Scottish TOs, the scale of growth required in RIIO-T3 is of a magnitude greater than that faced in any previous price control period and this has a direct impact on the associated scale of indirects. Consequently, in our Business Plan we highlighted the need for our staff to grow by 1,422 (+151%) by 2028/29. Ofgem's current proposals significantly underfund these allowances. This is an issue of significant concern, **as it results in a c.60% shortfall in funding**. Critically, this would mean we cannot fund essential engineering resources—such as design and early-stage engineering work—that are required well in advance of project delivery. Without adequate funding, we are at risk of falling short of delivering the accelerated project expectations to meet CP2030.

[11] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*
[12] Annex 2.3. NERA. (2025). *2.3 2025.07.24 US Allowed Cost of Equity vs Ofgem DD*
[13] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*

The benchmarking has resulted in a counterproductive reduction on our CAIs and BSCs. We understand the benchmarking was difficult to do, as although we have fully adhered to the guidance this was not universal across TOs and the data was not presented consistently by all parties. Consequently, the benchmarking is immediately eroded in terms of its robustness and validity by Ofgem's decision to use a derived Baseline view of company plans rather than Best-View forecasts.

This is the key driver of the underfunding in the DD; we have presented our costs on a Best -View basis in line with Ofgem's Business Plan Guidance to support the total investment required to meet the UK and Scottish Government's Climate targets. **Ofgem's shift to using Baseline costs in DD has resulted in an undue weight being placed on historical analysis which does not reflect the step-change in investment and organisational scaling that is now essential for successful delivery**. The approach set out in the DD fails to capture the forward-looking nature of the energy transition, and the infrastructure demands it entails.

To address this Ofgem must follow its own published Business Plan Guidance[14] by using Best-View data and to do this consistently across all TOs. We note that Ofgem continues to engage with TOs on providing Best View forecasts, which we welcome. This approach is more likely to provide a more robust view of the required expenditure for each of the networks. To the extent that this results in material changes to the treatment of allowances we would expect Ofgem to provide all stakeholders with the opportunity to comment on the impacts through a focused consultation in advance of FD.

Address flaws in the indirects cost assessment

The benchmarking itself was flawed. The limitations in these mechanisms are compounded in the approach to modelling CAIs and BSCs. The flaws in indirect benchmarking have led to implausible efficiency scores. For instance, our RIIO-T3 CAI efficiency score is calculated at 291%, compared to 51% for National Grid Electricity Transmission plc (NGET), despite us being identified as the most efficient operator in the historical CAI regression. **This discrepancy highlights the need for a more credible and transparent benchmarking approach. Four key flaws and areas to be addressed for FD are**:

(1) The analysis relies on the results of a single regression model for both CAI and BSC assessments, despite the existence of alternative regressions that are equally robust. This narrow approach fails to capture the full spectrum of plausible outcomes and introduces unnecessary bias into the cost assessment process. A more robust approach, consistent with regulatory precedent, would be to consider a range of sensible models and triangulate across them to mitigate bias risk.

(2) A further concern is the inclusion of a statistically insignificant time trend within the regression model. This element alone results in a £51 million reduction in our CAI allowance, underscoring the statistical fragility of the methodology and its disproportionate impact on us.

(3) The application of a 50:50 weighting between historical and forward-looking data is wrong and Ofgem has not provided a clear justification. This method does not adequately reflect the step change in growth required by the Scottish TOs, who are starting from a lower base in RIIO-T2. As a result, the approach fails to account for the unique investment trajectory of these operators.

(4) Ofgem's statistical tests focus solely on historical data, without assessing the significance of relationships in the RIIO-T3 period. In practice, there is a clear structural break between the historical and the RIIO-T3 period. This oversight raises concerns about the relevance and applicability of the findings to future investment scenarios.

For Ofgem to resolve these flaws in the approach to modelling, we propose a series of practical and evidence-based alternatives. Our preferred alternative (Preferred Approach 1) is to use forward-looking regression analysis based on Best View data on the basis that this approach will provide the most robust view of the level of indirects investment required to support growth. In the absence of Best-View information, we recommend applying sequential modelling based on a triangulation of several regressions to estimate efficient costs in RIIO-T2 and then using forecast Full-Time Equivalent staff

[14] https://www.ofgem.gov.uk/sites/default/files/2024-07/RIIO-3_Business_Plan_Guidance.pdf

(FTEs) as a primary cost driver for growth (Alternative Approach 2). Following this approach, statistically insignificant variables, such as the time trend, should be removed from regression models. A third, simpler but less robust alternative (Alternative Approach 3) would be to place greater emphasis on forward-looking ratio analysis, with a suggested 75% weighting for Scottish TOs. Preferred Approach 1 and Alternative Approach 2 would address critical flaws in the current analysis whilst Alternative Approach 3 would partially mitigate these critical flaws. Adopting a more robust alternative approach would provide allowances more aligned with the demonstrated investment requirements in RIIO-T3.

We recognise that Ofgem has sought to address the challenge of supporting additional growth by introducing new mechanisms to enable additional funding. This includes the CAI Use-It-Or-Lose-It (UIOLI) and the BSC Re-opener. While we welcome the intention behind these mechanisms, both currently contain flaws which must be addressed otherwise a significant proportion of our required CAIs and BSCs will remain unfunded thereby compromising our ability to deliver the required investment to meet CP2030 timelines.

The CAI UIOLI mechanism excludes projects valued under £25 million, despite the fact that 63% of our RIIO-T3 projects fall below this threshold. This includes a substantial portion of forecast generation and demand connection schemes, which are critical to meeting future energy needs. These points can be addressed by raising the CAI UIOLI ratio from 10% to 15% and removing the £25 million threshold to ensure all projects receive appropriate support. We also propose introducing a mechanism that allows additional indirects funding where the full CAI UIOLI has been utilised.

Similarly, the BSC reopener threshold is set at 15% of BSC and non-variant Totex, a level that is both too high and which will be reached too late in the price control to be effective. The inclusion of a Totex threshold introduces a perverse incentive, whereby efficiencies in other cost areas could inadvertently prevent the reopener from being triggered. Additionally, the absence of mechanistic triggers and early-year funding windows poses a risk to timely investment. Delays in funding could have long-term consequences for infrastructure delivery and the achievement of strategic energy objectives. This can be addressed by enabling a more mechanistic/ automatic BSC Re-opener mechanism based on FTEs and capital expenditure growth that recognises that the timing of required investments will vary by TO. This would provide more responsive and effective funding triggers and could be supplemented by extending the CAI UIOLI mechanism to BSC

To evidence these concerns, we are submitting two independent reports from external consultants - NERA[15] (see Annex 3.1) and Economic Insight[16] (see Annex 3.2) - which rigorously identify the flaws in Ofgem's comparative cost assessment for indirects, quantify the materiality of these issues and identify changes that would address these issues.

The cumulative impact of these shortcomings in the costs assessment process is that Ofgem's DD falls short of aligning the proposed allowances with the scale of growth required, in the time needed, to meet the ambitions of CP2030. This is particularly concerning given Ofgem's own acknowledgments of the need for "unprecedented network expansion"[17] in electricity transmission and its economic growth and net zero duties.

Addressing other key gaps in totex funding

Several key areas of totex and associated thresholds have been proposed without adequate consideration of the submitted evidence or by relying too heavily on RIIO-T2 data. This results in inadequate allowances which would compromise our ability to provide the necessary investment to support the required growth in our network. The key areas to be addressed are as follows:

(1) **Cap on Risk and Contingency allowances is entirely arbitrary and prohibitively low** - Risk and Contingency (R&C) allowances are capped at 5% without explanation, a reduction from the

[15] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August.
[16] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August.
[17] https://www.ofgem.gov.uk/sites/default/files/2025-06/Draft-Determinations-Overview-Document.pdf Page 8, Page 10, 8.1 and 9.1

7.5% allowed in RIIO-T2 and materially lower than the evidence put forward by each of the TOs in Business Plans (e.g. our large sample data based analysis demonstrates R&C of 10.9%-12.9% for load projects and 8.9%-9.2% for non-load projects, SHET indicates an increased construction risk position of [redacted], and NGET states a risk contingency factor of [redacted] for early phase projects). The 5% cap on R&C doesn't reflect the increases in risk due to the increased scale, pace of delivery and complexity of RIIO-T3 programme capex projects and represents a reduction in project allowances. We consider that Ofgem should carry out further quantitative and qualitative analysis of the evidence put forward by each of the TOs in their Business Plan submissions, responses to SQs and DD responses. Ofgem's allowance for R&C should also reflect growing risks associated with the broader application of delivery incentives and licence obligations relating to capex projects.

(2) **Approach to NOCs is flawed and risks underspend on core operational and maintenance activities** - The NOCs modelling is based on the lower of RIIO-ET2 or ET3 values, creating a ratchet effect that suppresses future allowances and duplicates the expected efficiency gains already extracted by the Ongoing Efficiency (OE) mechanism. The thresholds for applying annual average unit costs for NOCs—set at 25% and £1 million—also lack a clear economic rationale and result in a mechanism that fails to account for changes in workload between periods. The allowances for NOCs must remove these arbitrary ratchets and reflect the justification put forward on cost increases by each of the TOs including competitive market evidence and other factors.

(3) **Operational Technology (OT) underfunding as result of IT&T cost assessment** - We have significant concerns with Ofgem's assessment of our OT investment submission. The DD proposes an average 50% reduction in our requested funding which is the result of an arbitrary allowance reduction driven not by benchmarking but by a qualitative review of the engineering evidence provided. Our OT systems are vitally important infrastructure, meaning any disruption could have serious consequences for public safety and national security. These systems are essential for protecting the public and our operational teams, maintaining the stability of the electricity network, ensuring secure and resilient connections and providing suitable communication channels for a potential Emergency Restoration in the case of a national supply loss. Underfunding these systems puts the reliability and security of the transmission network at risk. Further detail is provided in Chapter 4.

Separately the justification for significant funding reductions in our IT+T projects is also insufficient for BSCs and Non-Op capex and based on the same flawed determination process as our OT investment submission, again relying solely on vague claims of "poor evidence" for BSCs and "fair evidence" for Non-Op Capex.

Address the interaction with RPEs and OEs

The errors in the DD cost assessment are exacerbated when compounded by a flawed methodology in Real Price Effects (RPEs) and the approach to OE. We have seen the impact first hand in the current price control with operation of RPEs in a high inflationary environment resulting in reduced allowances. The importance of BS & CAIs to launch projects and enable delivery at pace cannot be understated. They are inherently engaged early in the project lifecycle and are a large percentage of these support costs and therefore materiality should not be viewed against aggregate project totex.

Underfunding indirects compounded by RPEs and OE reduces our funding, further exacerbating the risk to the transmission investment needed to accelerate delivery at the pace required to meet CP2030.

Real Price Effects

As part of our RIIO-T3 business plan and Cost Assessment Annex (page 82 of our RIIO-T3 Business Plan[18] and section 9.1 of our Cost Assessment Annex[19]), we have proposed a more refined approach to RPEs, recognising the increasing complexity and cost pressures facing electricity transmission. Our aim

[18] SP Energy Networks. (2024). *How we get there*. p82
[19] SP Energy Networks. (2024). *Cost Assessment and Benchmarking Approach (including RPEs & OE)*. section 9.1

is to ensure that the regulatory framework keeps pace with the realities of delivering critical infrastructure in a rapidly evolving energy landscape.

We proposed three key improvements:

- **Greater granularity in material indices**, to better reflect the specialised inputs we rely on.
- **Labour indices that more accurately mirror actual cost structures**, ensuring fairer treatment of workforce-related expenditure.
- For projects that **Cost and Output Adjusting Events** apply, set a threshold in line with ASTI precedent of 5% rather than the 4-fold increase set by Ofgem of 20%

However, Ofgem's DD indicates a continuation of the RIIO-2 RPE methodology. We believe this overlooks two growing risks that could undermine the sector's ability to deliver efficiently and sustainably:

Basis Risk – Misalignment with Real Costs

The current indices are too broad and fail to reflect the specific materials and services central to electricity transmission. Pan-European energy transition efforts are creating capacity constraints and driving up supplier margins—pressures that are not captured by the existing 'all-infrastructure' indices. In addition, the materiality threshold excludes more detailed indices (e.g., asset-specific price series), leaving some TOs, including SPT, disproportionately exposed to rising input costs.

Composition Risk – Static Assumptions in a Dynamic Environment

Composition Risk involves the consequences of fixed ex-ante weights which do not reflect the changing nature of TO expenditure. As investment priorities shift, the actual mix of inputs diverges from Ofgem's assumptions. This misalignment increases exposure to cost volatility and makes it harder to plan and deliver efficiently. The reliance on ex-ante allowances within uncertainty mechanisms adds further unpredictability, reinforcing the need for more flexible and responsive price adjustments.

Proposals for future-proof RPE framework

To ensure a sustainable and useful RPE framework, the RPE mechanism needs to be calibrated in a manner commensurate with its function, namely to address cost increases outside of our control. We are therefore asking Ofgem that more targeted RPE adjustments are developed. We would also suggest **reducing or removing the Materiality Threshold** and applying a consistent set of RPE indices across all TOs. Using existing asset-specific indices (e.g., for plant and equipment) would improve fairness without adding complexity. Finally, we would additionally suggest **developing targeted RPE indices for uncertainty mechanisms**, by linking unit rates for key activities (such as line and transformer installation) to dedicated price series. This would ensure that cost allowances are directly aligned with the market conditions most affecting delivery.

We believe these changes are essential to maintaining a fair, transparent, and resilient regulatory framework—one that supports efficient investment and protects consumers from unnecessary cost escalation.

Ongoing efficiency (OE)

In our Business Plan we set out the reasonable range of RIIO-T3 OE and selected an ambitious target of 0.4% pa (from a range developed by Oxera[20] of ~0.0%-0.5%). This was based upon reasonable economic comparators of productivity (presenting 3 different industry comparator sets).

Ofgem's proposal to **maintain the 1% of previous regulatory periods** is not supported by a proper assessment of the available evidence. It appears to be based on evidence from an overly long-time horizon, and the decision to take account of irrelevant evidence in relation to the Information and Communication sector as part of the comparator set. As set out in this response, removal of this sector (given its irrelevance in productivity terms to the ET industry) results in an expected OE estimate that is

[20] Oxera. (2024). *Ongoing efficiency and real price effects.* p4

skewed negative, but no more than 0.2% which is inside the range set out by Oxera in their "Ongoing efficiency and real price effects" supporting document.

We suggest that Ofgem considers only sound economic principles including reasonable comparators, and a productivity time horizon which is broadly in line with feasible productivity growth in the post-Great Recession period, when developing its OE position.

Providing an appropriate balance of incentives and growth mechanisms is essential to securing timely funding certainty and enabling delivery at pace.

Creating the right conditions to foster innovation, efficiency, and growth is essential, particularly as 86% of our expenditure would be enabled by growth mechanisms under the Draft Determination. As such, we have a critical dependency on the effective operation and administration of these mechanisms. In the immediate term, this includes the robust, comprehensive and accurate development of appropriate licence conditions. Those conditions must be sufficiently developed at the statutory consultation to enable us to engage with them and have a clear understanding of how they will work in period. We support the ambition behind the introduction of new incentive mechanisms; however, we remain mindful of the significant engineering effort required to define their operation and ensure their seamless integration into licence-based delivery including the target date setting of the CSNP-F as well as well-established ODIs like ENS. As an example, we are particularly supportive of the new Innovative Delivery Mechanism which is recognising that innovation will play a key role in meeting delivery targets, however the proposal is very vague in the DD and needs further development. Ofgem's proposed approach of an expert panel is too subjective and we propose a more objective approach that sets out measurable criteria.

Provide a balanced risk package

We welcome the intent of Ofgem's proposed Output Delivery Incentives (ODIs) and the adoption of our stepped TIM approach. We consider the proposals reflect the behaviours required for RIIO-T3: focusing on delivery for CP2030 whilst maintaining resilience of our network for consumers.

However, following our analysis of the ODI package, the proposed targets and criteria set by Ofgem in individual ODIs have made the targets unachievable with little reward likely to be available. Although maximum reward and penalties appear to be more symmetrical for the RIIO-T3 package, the likelihood of achieving rewards has decreased significantly since RIIO-T2. Our likely forecast, based on a number of uncertainties and assumptions show it is more likely to be around **0.1%** of RoRE (£4.7m[21]).

The increased scale of investment and changes to the regulatory package since RIIO-T2 has resulted in risk increasing overall. We submitted an independent report[22] with our business plan that demonstrated this, which has been updated following the Draft Determinations. The headline is that regulatory risks have continued to increase in Ofgem's RIIO-T3 DD in comparison to RIIO-T2. This does not align with Ofgem's RIIO-3 impact assessment that the incentives package has been taken into account due to the scale of the totex risks[23], given the forecasted RoRE impact of 0.1% we do not believe this has been taken into account. Although we're supportive of Ofgem's adoption of our stepped TIM proposals, we believe a more asymmetric TIM having a greater sharing factor in underspend will encourage efficiencies at a time of unprecedented investment and potentially help balance the overall package.

Streamline regulatory processes to support investment at pace

RIIO-3 marks a transformative shift in regulatory cycles, with RIIO-T3 introducing dynamic growth mechanisms that are reshaping how we plan and deliver our network investments. Unlike previous frameworks, RIIO-T3 leverages mechanisms like ASTI, HND (£2.9bn), and tCSNP2 (£4bn) to unlock

[21] 2023/24 prices, per Ofgem's Draft Determinations BPFM, https://www.ofgem.gov.uk/consultation/riio-3-draft-determinations-electricity-transmission-gas-distribution-and-gas-transmission-sectors
[22] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*. See section 1.7.5 of this response
[23] https://www.ofgem.gov.uk/sites/default/files/2025-06/RIIO-3-Draft-Determinations-Impact-Assessment.pdf Ofgem's RIIO-3 Impact Assessment page 10 and 18

unprecedented funding and accelerate decision-making—replacing outdated Network Options Assessments that hindered progress.

We have, along with Ofgem and the NESO, embraced this evolution, aligning our RIIO-T3 Business Plan with the UK's CP2030 and Net Zero ambitions. A projected £7.5bn in network growth will be enabled by these mechanisms, with the Load Re-opener (LR), UIOLI pot, and CSNP-F playing pivotal roles in delivering both near-term and strategic infrastructure. It is therefore critical that we develop the licence to ensure the effective operation and administration of these mechanisms. Our ongoing constructive engagement with Ofgem centres on streamlining and automating regulatory processes to reduce regulatory burden and accelerate investment. The following mechanisms are critical to achieving this:

- **Automatic Volume Driver**: Historically successful in enabling over 11GW of connections, but RIIO-T3's proposed unit rates risk an estimated £95m funding shortfall. Because that the materiality threshold is set at more than four times the RIIO-T2 value, this mechanism is therefore non-functional. We will work with Ofgem to support appropriate recalibration of the mechanism based on actual costs and environmental initiatives to ensure viability and automation. Otherwise, this could delay investment in connections following connections reform and place more regulatory burden on Ofgem to approve individual projects.
- **Automatic Load UIOLI Mechanism**: Designed for atypical connections outside the volume driver scope and lower materiality investments. We require the pot to be increased to £270m or it should be subject to annual automatic replenishment to avoid early depletion and maintain flexibility.
- **Streamlined LR**: A cornerstone for CP2030 delivery. We propose increasing Pre-Construction Funding (PCF) from 2.5% to 14.5% (3.3% PCF and 11.2% Early Enabling Works (EEW)) this recognises Ofgem's new definitions of PCF and EEW which includes the increased scope of PCF, applying automatic eligibility triggers, and raising the threshold to shift more projects into the UIOLI mechanism —reducing regulatory overheads and potential project delays.
- **Streamlined CSNP-F**: Essential for strategic wider works under the CSNP. We call for clearer project distinctions between CSNP-F and LR, and automation of pre-construction funding upon NESO confirmation to avoid delays and uncertainty. As noted in the risk section, a COAE threshold of 5% for CSNP-F and the LR.
- **Non-Load Re-opener**: We highlight a gap in the framework for asset interventions not evident at the time of plan submission. The dedicated non-load mechanism proposed does not address to address the emerging issues beyond baseline allowances.

These mechanisms are not just regulatory tools—they are enablers of national policy. By streamlining approvals and automating funding, it will allow us to deliver critical infrastructure at pace, ensuring the UK meets its CP2030 and Net Zero targets. This collaborative approach with Ofgem and other stakeholders reflects a shared commitment to innovation, adaptability, and strategic foresight.

<u>Provide timely clarity and certainty through licence drafting</u>

In parallel with the DD process, the licence drafting for RIIO-3 is ongoing. Our initial view from Ofgem's publication of the informal licence drafting consultation is that until further clarity and analysis has been provided on the various price control instruments, such as the full publication of the Price Control Financial Handbook (PCFH), a complete understanding of the wider impacts cannot be achieved. Due to the informal nature of the consultation, Ofgem has not provided associated guidance documents, updated the RIIO-2 principles of use for associated documents, supplied a tracked change version of the licence change nor issued a Reasons and Effects document. We have expressed our concern with this process, including that this does not represent best regulatory practice.

This, combined with the lack of certainty on critical policy aspects of the price control such as the ODIs and Re-openers is of significant concern at this stage. For example, the Volume Driver, a significant and well-established mechanism to provide automatic funding for connections projects, did not have unit rates

updated appropriately in the RIIO-T3 Draft Determination. In addition, upon review of the draft licence condition there appears to be a two-year funding gap where the volume driver will be in operation for years 2031-33 but in the algebra formula in the licence does not allow recovery in these years. This is just one example of an existing RIIO-T2 mechanism which has not been updated appropriately in either the licence or Draft Determination causing great concern given the reliance on such mechanism within the RIIO-T3 period. We have also seen within the consultation conditions such as the CSNP engagement licence condition which do not reflect working group feedback and new conditions[24] such as the non-load re-opener for the first time, which have an open policy position in the DD. We understand Ofgem's next step following the informal consultation is for a statutory consultation in December following FD this will not provide licensees with sufficient time to review these conditions in full so as to undertake the required analysis and due governance. We urge Ofgem to provide a tracked change version of the licence prior to statutory consultation following the consideration of feedback during the licence working groups and informal consultation process.

In addition to impacting the draft licence conditions the ongoing policy development and analysis from Ofgem has impacted the response to this DD for example critical meetings such as the Cost Assessment Working Group (CAWG) 23 was three working days before this response, whilst the operational technology bi-lateral was two working days before this response. We were particularly disappointed in the lack of detailed justification or analysis on the OT and engagement[25]. The overall analysis and policy development process from Ofgem has impacted our ability to update or revise positions which have already been through governance and assurance. We are now at an advanced stage of the price control development, material changes to policy presents and unquantifiable risk, in an environment where regulatory risk has increased from previous price controls.

Why this matters - cumulative impact of DD

Our network will be critical to the successful delivery of CP2030 and ultimately to realising both Government and Ofgem's growth and net zero objectives. This is clearly demonstrated by the following chart which highlights our network's key position as a lynchpin of the GB energy system and thus key to its future success.

The map below (Figure Exec-1) shows projects that NESO and the UK Government have identified as critical to meeting CP2030, which we will deliver during the RIIO-T3 period, primarily through the Load Reopener (LR). However, these represent only part of our planned investment for RIIO-T3; we have also included projects that we expect to deliver under the LR based on our own forecasts (Figure Exec-2). We are strongly committed to making the investment that will support growth and net zero objectives.

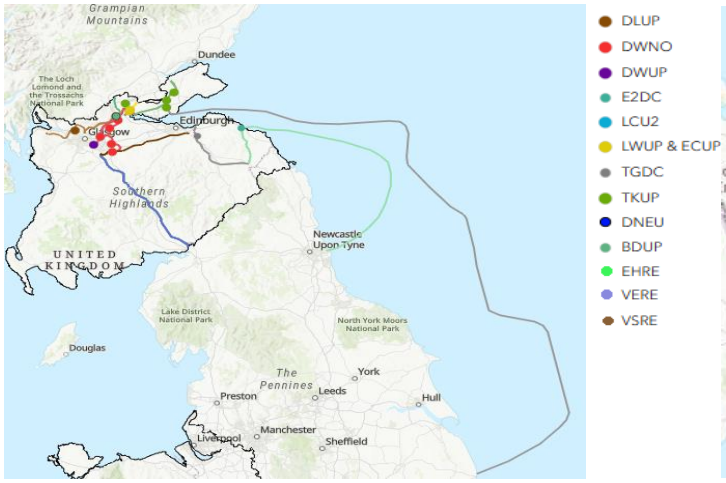


Figure Exec-1 - SPT CP2030 Projects

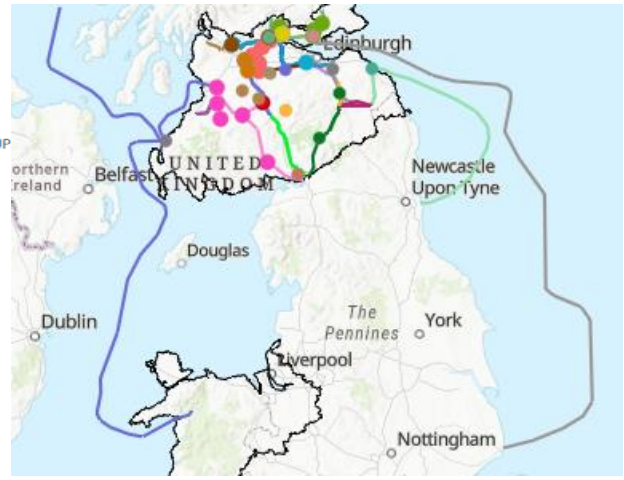


Figure Exec-2 - SPT's Best View Projects (including CP2030)

[24] This includes conditions: 3.9 Operational transport carbon reduction Price Control Deliverable (OTCt), 3.10 Non load re-opener, 3.13 Closely associated indirects UIOLI and 3.44 Atypical PCD
[25] Meeting 22.8.25

Addressing each of the priority areas we have highlighted above will have a significant positive impact on our ability to deliver that investment.

These represent a substantial shortfall which would compromise our ability to deliver.

Next steps towards final determination

There are many positive aspects of Ofgem's DD but also key issues that need to be addressed. On that basis, we have used this response to provide further evidence-based proposals that enhance Ofgem's DD. By reflecting our proposals, we consider it is possible to provide a package of investment in RIIO-T3 that supports the growth and delivers value for GB energy customers both now and in the future. We are confident with our proposed adjustments to the draft determination we will deliver the transformation, within our Licence area, and fully achieve shared decarbonisation goals. We encourage Ofgem to establish additional working groups to ensure that the sector moves forward together.

It will be imperative as we move towards FD over the coming months that we see the robust, accurate development of appropriate licence modifications, and that we have the opportunity to scrutinise and comment on these modifications in advance of the Statutory Consultation (given the issues which we have identified with the informal licence drafting consultation process).

We look forward to continuing our engagement and working constructively towards a final determination which fully delivers the objectives of the UK's energy transition.

[26] Presented at Ofgem Director bi-lateral on 14-08-25

Chapter 1 - Ensuring an investable finance package

1.1 Overview

1.1.1 We welcome the changes Ofgem has made to the financial package since the Sector Specific Methodology Decision (SSMD) and view this as a positive step in the right direction. Ofgem has rightly recognised the centrality of the financial package in achieving the required investment for the delivery of net zero and wider customer benefits.

1.1.2 However, further changes are required to secure an investable RIIO-T3 package that can enable delivery of net positive outcomes for customers and society. The return in equity Ofgem proposes in the DD is significantly below the required levels TOs set out in their business plans. The TOs have submitted clear and persuasive evidence that supports a return on equity in excess of 6%, on a 55% basis.

1.1.3 Ofgem's proposed DD package, and in particular the return on equity, risks undermining efforts to attract the unprecedented investment required; to deliver key targets such as CP2030 and Net Zero; and to allow the RIIO-T3 price control to foster UK economic growth, in line with Ofgem's responsibilities under the Growth Duty[27].

1.2 Further work on investability

1.2.1 We recognise positive changes in Ofgem's proposals including; a RAV weighted CoD mechanism, an adjustment to capitalisation rates in light of financeability and investability challenges, and expanded beta comparators. However, Ofgem has not developed their investability framework to sufficiently account for the combined challenges, of:

- the material changes to the macroeconomic environment since the last price control review (see Figure 1-2); or
- the very significant change in what networks will be required to deliver to achieve CP2030 and Net Zero[28].

1.2.2 The DD's financial package moves further towards an investable position than was the case for the SSMD and contains a large amount of well received positive language around investability. However, Ofgem's approach to investability has been to use their narrow set of established CoE cross checks as dual purpose, for both cross-checking purposes, but also an investability test. This approach is far more limited than our own proposed investability framework set out in our business plan[29] and used to assess the DD financial and regulatory package below (see section 1.5), where CoE cross-checks were part of a wider set of assessments. We are disappointed that Ofgem has not adopted these tests to robustly assess investability, and we do not believe Ofgem can assert the financial package is investable without a more comprehensive investability test.

1.2.3 To compete for capital internationally, high performing electricity transmission networks should have a reasonable expectation of returns in excess of 10% and must provide a sufficient premium to equity investors over returns available to debt investors. The baseline returns and incentives available fall short of that. We understand Ofgem views their DD position and proposed 7.7% CoE (nominal, assuming 2% inflation) as not significantly different to the 10% nominal returns available in the US, however what this signals to investors is that nominal returns in the US are more than two percentage points higher than proposed in the UK.

1.2.4 Ofgem has been unbalanced in their approach to setting allowed returns and investability and failed to appropriately engage with CoE cross checks. In particular, Ofgem has applied an inconsistent quality standard to its own and ENA's proposed equity cross checks leading to it

[27] Department for Business & Trade. (2024). *Growth Duty: Statutory Guidance – Refresh - Growth Duty: Statutory Guidance Statutory Guidance under Section 110(1) of The Deregulation Act 2015*.p5.
[28] SP Energy Networks. (2024). How we get there. p10.
[29] SP Energy Networks. (2024). *How we get there*. p84.

relying on a biased set of cross-checks. A balanced set of cross checks clearly demonstrates that Ofgem's proposed RIIO-T3 CoE is too low (section 1.6).

1.2.5 Similarly, on TMR the UKRN has acknowledged that a 'through the cycle' approach could yield a TMR which is either too low or too high. TOs have proposed a balanced approach with a reasonable flex around a stable TMR position to reflect the current economic environment[30] (where, from a macroeconomic perspective interest rates are high) which can be adopted on an enduring basis. What's at stake for customers and society is too great in RIIO-T3 to allow a lower TMR than is required.

1.3 Now is the time to follow through on the investability promise

1.3.1 TOs, like potential investors, have been encouraged by Ofgem's language around investability. Ofgem has set the expectation that it will deliver an investable package. As we head towards FD we are at a critical juncture. It is time that, having signalled investability as an important theme for RIIO-3 price controls, Ofgem follow through and holistically consider the required components of an investable package and test whether the proposals meet those requirements.

1.3.2 While we do not expect that an allowance below investor expectations would lead to an immediate withdrawal of capital, it could be a rational investor's response to scale back investment in favour of other opportunities. Similarly, potential investors may be deterred from deploying their capital in the sector. The impact of these rational investor decisions may not be immediately noticeable, where the full impact may only be apparent when customers are exposed to sub-optimal outcomes and policy objectives are not achieved.

1.3.3 We do not want to lose investor confidence at this critical stage. This DD position will be below what investors expect from the FD.

1.3.4 We remain fully committed to delivering our Business Plan, we are confident there is still time to achieve a regulatory and financial package that is investable.

1.4 The RIIO-T3 challenge – cost and benefits

1.4.1 What is being required of TOs during RIIO-T3 and beyond cannot be understated, the mobilisation of resources to enable the scale and pace of investment delivery to achieve net zero is unprecedented. Ofgem and TOs have been transparent about the costs to customers of increased investment, however Ofgem has not fully set out the benefits case for the delivery of TOs' business plans. The overall benefits case is strikingly net positive (see our Finance Annex sections 2.2 and 3.11).

1.4.2 The positive impacts that the successful mobilisation of capital delivers, not just for bill payers but society as a whole, can also not be overstated. These benefits are not only felt in the direct bill reductions which offset investment costs over the RIIO-T3 period, but also the longer term direct bill reductions after RIIO-T3, in addition to economic growth driven by this investment which has an immediate and enduring impact on the UK economy, including GDP, jobs and household income, and further the society wide benefits of achieving net zero which the OBR reaffirmed in their July 2025 report[31] setting out that the cost to achieve net zero is significantly lower than the cost of inaction.

1.4.3 The investability risk we currently face is therefore significant. To achieve a FD, which is in the best interests of customers, we ask that Ofgem robustly delivers on its investability promise. To ensure the FD supports the delivery of CP2030 and associated economic benefits, allowed returns on equity should increase in excess of 6.0% on a 55% basis, against the backdrop of

[30] Annex 2.6. Frontier Economics. (2025). *2.6 FE-Assessing Regulators Approach to Setting the TMR*. section 3.6.9
[31] https://www.carbonbrief.org/obr-net-zero-is-much-cheaper-than-thought-for-uk-and-unchecked-global-warming-far-more-costly/

other available opportunities, to incentivise investors to mobilise capital at the scale and pace required to deliver these firmly net positive benefits to our customers and society.

1.4.4 As an example, a 50bps increase in the allowed return would increase customers' bills for transmission network charges by less than £1.50. This is minimal in comparison to the direct and indirect benefits an investable package unlocks.

1.5 Investability Framework and Key Challenges

1.5.1 We recognise the very positive steps since the SSMD, however Ofgem's DD overall fails our investability test.

1.5.2 Ofgem has set out a clear expectation that they will assess and deliver an investable package. Unfortunately, Ofgem has not fulfilled its investability promise in the Draft Determination.

1.5.3 Ofgem has not set out a robust test for investability, relying on a limited set of cross checks which present a biased view of the appropriate level of return. Without a comprehensive test Ofgem will not be able to assert that their RIIO-T3 regulatory and financial package is investable.

1.5.4 In our RIIO-T3 Business Plan we developed an investability framework, we now measure Ofgem's DD against this framework:

Table 1-1 - Investability Framework and the Draft Determination's Performance

Measure	Assessment	Analysis
A fair allowed return aligned with the level of risk	Fail	Ofgem's DD has failed to take account of the changes in macro-economic conditions since RIIO-2, and fully account for forward looking risk.
Cashflows sufficient to make debt repayments	*Pass	We deem that cashflows are sufficient to make debt repayments for RIIO-T3, however Ofgem's approach to cashflows sufficiency needs to be reviewed for future price control periods, such that a more enduring solution is available to solve cashflow problems beyond the quick fix.
A fair bet for investors - asymmetrical balance of risk	Fail	It's essential the incentive package is set to giving networks and their investors' confidence that high performance will result in additional real returns, On balance, while positive steps have been made in respect of the risk balance, investors still face a asymmetric risk with no clear route to achieve 9-10% nominal returns, and so on a RoRE basis, given our assumptions, the DD incentives structure fails the "fair bet" assessment.
Investment grade credit rating, robust to shocks	*Pass	Whilst the target investment grade credit rating has been achieved for RIIO-T3, we have not been given comfort that the cash measures would achieve their intended effect per the rating agencies methodologies. Passing this test is on the assumption that Ofgem's policy has the intended effect on the credit ratings.
Cross-checks to other available investment opportunities	Fail	Ofgem has been unbalanced in its assessment and use of cross checks and have disregarded strong evidence provided by debt based cross checks showing the CoE needs to be higher. Further, the allowed return falls short against other relevant comparators, including US based returns, and Sizewell C allowed returns.

Remuneration for the cost of raising investment	*Pass	Equity issuance allowance has remained at 5% which we deem as sufficient for RIIO-T3. However, we believe additional indirect costs of equity issuance may not be fully accounted for in the allowance.
Reasonable dividend payments	*Pass	In line with our business plan, Ofgem has set the dividend yield at 3%, which was the same working assumption in the previous price control period. We believe this to be reasonable for RIIO-T3, however evidence suggests investors may expect a higher dividend from regulated networks.

*Adequately passes for RIIO-T3, however enduring approach needed for subsequent price controls.

1.5.5 Our investability framework therefore signals significant issues with the investability of the draft determinations package, meaning the regulatory and financial package, as set out in DD suggests a significant risk that may not deliver sufficient outcomes in RIIO-T3.

1.5.6 However there remains a pathway to achieving an investable package for RIIO-T3 in FD. Below are the key areas which must be resolved to pass the investability test. *The analysis here is set out in more detail in Annex 2.7*[32]:

(1) The baseline return is too low, when considering:

(1)(a) The increased risk associated with RIIO-T3 investment (set out further in section 0 & 1.12 below);

(1)(b) The change in macroeconomic conditions over the last 5 years (set out further in section 1.6 & 1.12 below);

(1)(c) A balanced scorecard of cross checks including debt based cross checks (set out further in section 1.6 below);

(1)(d) Other comparators including US returns, Sizewell C returns, and returns available to the gas networks (set out further in section 1.6 below).

(2) There is downside risk across the framework that lowers expected returns further:

(2)(a) Ofgem has proposed a 1% Ongoing efficiency challenge although the evidence shows this level has not been achieved in any sector since 2008 (set out further in Chapter 9 - Ongoing Efficiency);

(2)(b) There is a lack of totex funding or pathway for funding for indirect costs through baseline totex and uncertainty mechanisms. We believe Ofgem has to revisit its overall approach for indirects which have communicated to Ofgem separately (set out further in Chapter 2);

(2)(c) Risk and contingency allowances are proposed to reduce from 7.5% in RIIO-T2 to 5% in RIIO-T3. Ofgem has provided no evidence for this decision (set out further in 2.1.13); and

(2)(d) The lack of a workable reopener framework. Evidence from recent RIIO-T2 reopeners demonstrates this is a material risk and would reduce expected returns, unless there are significant changes to the framework proposals (set out further in chapter 6 of this response).

[32] Annex 2.7. Oxera. (2025). *2.7 Oxera - TOs ET3 investability*

(3) The incentive framework is incomplete and insufficient (for further information on each individual ODI see Chapter 5 - Incentives of this response) to bridge the gap to 9-10% nominal return:

(3)(a) Ofgem has, suggested that there is over 200 bps of outperformance from incentives. However, our own analysis continuing our strong performance in RIIO-T2, suggests on 10bps of outperformance could be achieved, with a maximum of 93bps possible

(3)(b) The scope to outperform is limited by costs being set relatively late for a material share of totex and by tight market conditions

(3)(c) Connections is a critical incentive for driving customer value and meeting Government's ambitions for Clean Power 2030 and economic growth. It is impossible, given the limited level of development, to assess if targets will be 'fair bet'. This incentive could have more downside risk than upside opportunity if targets do not reflect realistic 'deliverability' of connections alongside protections against delays out with TO's control

(3)(d) The Innovative Delivery Incentive is intended to drive innovation roll-out, but the panel-based assessment is too subjective. The design of the mechanism does not appear to be able to deliver the size of contribution to returns as Ofgem suggests (i.e. 50-100bps)

(3)(e) The eligibility criteria for defining what actions are incentivised under the SO:TO incentive are unclear. This ambiguity diminishes the power of this incentive which has, to date, provided material consumer benefit

(3)(f) Assuming an appropriate calibration of delivery dates, the new delivery incentive for projects under the CSNP-F regime is a positive step but the majority of projects that it will apply to will not be delivered until after 2030 resulting in this incentive having limited impact over RIIO-T3

1.5.7 We understand the challenge in designing an investable package and we are committed to working with Ofgem to resolve these challenges in a fair way for our customers.

1.6 Cross-checks

1.6.1 As Oxera set out in its "RIIO-3 risks and investability topics"[33] report that supported the ENA in the representative TOs' business plans, Ofgem should employ a wide spectrum of investability tests (as in Table -1) to ensure that its financial package is investable to raise the level of investment required. As part of this, Ofgem should have assessed its CoE figure against alternative CoE methodology, to ensure its CAPM-based estimate is robust. Unfortunately, Ofgem has been unbalanced in its application of cross checks, and inconsistent in the quality standard applied to its own cross checks and those proposed by networks which we set out in more detail below. Additionally, with increases in gilt rates, and given the logic set out in the ARP-DRP/hybrid bonds section below, we would expect returns to rise in kind [34] (to ensure that equity investors can still expect a return that remunerates them for their increased risk against debt).

[33] Oxera. (2024). *RIIO-3 risks and investability topics*
[34] Albeit perhaps not proportionally.

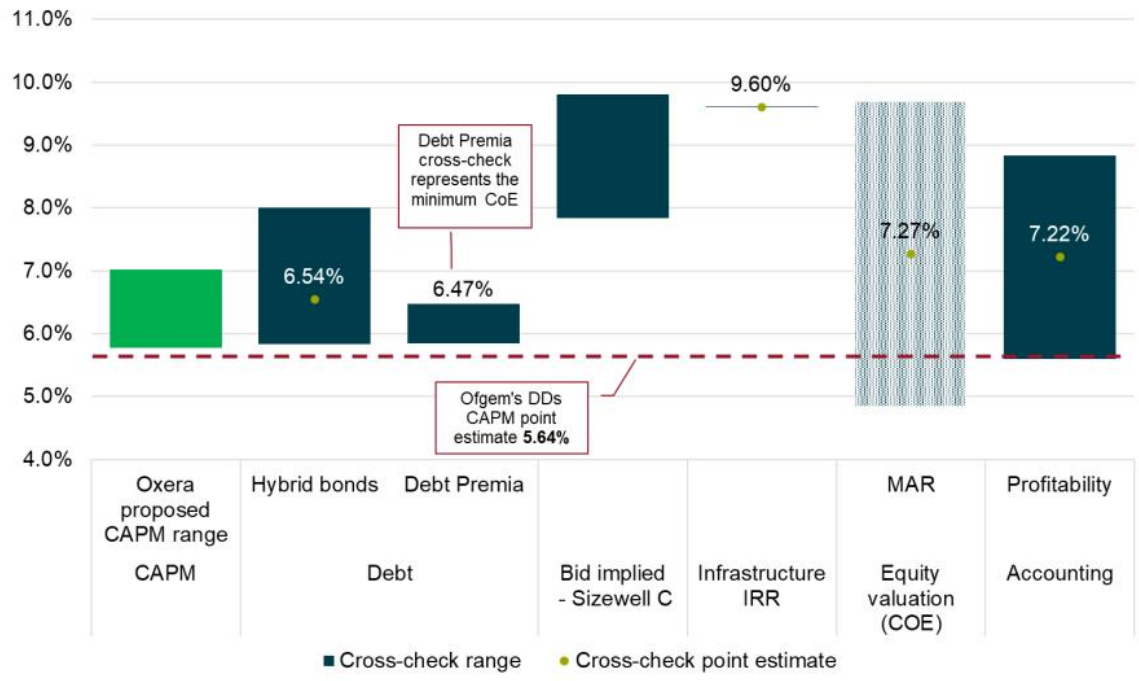
1.6.2 Balanced cross-checks suggest allowed returns are too low. Generally, the returns being offered by Ofgem's DD should allow investors to make an investable risk-related return for their investment in RIIO-T3. If we assess the return against both other measures of CoE (such as hybrid bonds, infrastructure IRR etc.) but also alternative investments, we identify that the DD CoE is insufficient to conclude that this is an investable package.

1.6.3 As can be identified below, and as provided in more detail in Frontier Economics' Updated Cost of Equity Cross-Check Evidence report, against alternative methods of estimating CoE, the DD CoE figure, though significantly higher than in the SSMD, is still at the bottom end of a reasonable range. This analysis also considered two additional cross-checking methodologies:

- ARP-DRP (asset risk premium-debt risk premium), the principle of which we set out in our Business Plan[35] which aims to compare the difference between the expected excess return from holding risky assets compared to riskless assets) and the debt risk premium, or the expected excess return to holding risky debt relative to riskless assets, and estimating an implied CoE range from this

1.6.4 Sizewell C – an infrastructure investment which is owned 15% by Centrica of a new nuclear power station in the UK. The allowed returns on this investment (10-12% nominal post-tax terms) can be deemed to be a relevant comparator to infrastructure investments, such that we can also use this as a cross-check of equity returns [36]

Figure 1-1 Comparison of Cost of Equity Cross-Checks [36]



Source: *Ofgem, Frontier Economics, Oxera*

Note: *We consider a 2% CPIH assumption and the Fisher equation to derive CPIH-real values for the cross-checks. For Debt Premia cross check we present Oxera's minimum CoE to cross check Ofgem's DDs CoE. We note that a higher minimum is needed to cross check Oxera's proposed CAPM range.*

1.6.5 Ofgem put undue weight on its previously utilised cross-checks, which are more limited, and in many cases more assumptions driven than the cross-checks that Frontier have deployed.

[35] SP Energy Networks. (2024). *Finance Annex*. p46.
[36] Annex2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*. Fig 1

Ofgem's cross-checks, if used in isolation, would conclude that a lower CoE is required (a roughly 5.8%[37] median cross-check implied CoE median far in excess of 7% implied by).

1.6.6 It also must be acknowledged, while accepting that the 60% notionally geared DD CoE is within the range of CoE cross-checks[38], albeit at the bottom end, that the 55% notional geared 5.64% is far below the middle of this range (and is entirely below the range for hybrid bonds). While notional gearing is inherently a consideration for investors and is embedded within the estimation of equity beta from asset beta, investors do not make investment decisions purely as a function of the notional gearing rate (which is a regulatory frontier) and therefore having insufficient actual returns against these cross-checks, even at 55%, should be examined.

1.6.7 Further, investor perception of the financial package is just as important as the facts and figures. Ofgem's RIIO-T3 investor call[39] made it clear that investors expect the same WACC as our 60% geared counterparts. The perception being that Ofgem expects TOs to have a greater proportion of funding from investors, in addition to a significant increase in funding required, and to do so for a lower allowed return. Ofgem should align TOs CoE to that at a 60% basis.

1.6.8 In order for a financial package, and more specifically the CoE to be considered investable, it must be sufficiently high such that it is robust against alternative CoE cross-checks but additionally should be internationally competitive. Given investors broadly have a global market to invest in, the returns that Ofgem sets out should be broadly in line with risk-reflective global return rates.

1.6.9 This principle considered, assessing the DD CoE against for example US comparators*, set out in further detail in Annex 2.3*[40], (as a good example of a global (non-European) market which has comparable data) shows a significant gap between US rates of return and the CoE set out in the DD Finance Annex of 5.64%. US returns are roughly 240bps difference than the equivalents in RIIO-T3 (7.75% [41], assuming 2% inflation, 55% gearing basis for both). Additionally, in understanding the risk-reflectiveness of the hypothetical RIIO-3 return, the following factors that the US sector are lower risk than the GB market, which, would mean (all other things being equal) we would actually expect the GB returns to be higher than the US equivalents:

1. Shorter regulatory period – usually around 3-4 years
2. Greater objectivity in setting allowed costs
3. True-up of pension liabilities
4. Less stringent output/quality of service incentives
5. The US regimes incorporate greater use of cost pass-through or true-ups
6. Empirically, that US electric utilities asset beta are lower than those of GB electric networks

1.6.10 The lack of similarity to US returns suggests that investors would potentially need to maintain their investment in RIIO-T3 despite having better alternative investments, and highlight the limits to the extent to which the DD financial package is investable.

[37] *Table 19 from DD Finance Annex - assumes a midpoint of 5.2% from the MARs range, and the other 3 cross-checks, and using a median, a mean would have biased both estimates upwards due to the far higher infrastructure IRR cross-check.*
[38] Using the 60% notionally geared DD CoE, the estimate is far below the Infrastructure IRR cross-check, at the bottom end of the hybrid bonds, ARP-DRP, MAR and profitability range, and is below the bottom end of the Sizewell C range.
[39] Ofgem. (2025). *RIIO-3 Draft Determinations investor call*. Available here: https://www.ofgem.gov.uk/transparency-document/riio-3-draft-determinations-investor-call
[40] Annex 2.3. NERA. (2025). *2.3 2025.07.24 US Allowed Cost of Equity vs Ofgem DD*
[41] Annex 2.3. NERA. (2025). *2.3 2025.07.24 US Allowed Cost of Equity vs Ofgem DD*. page 1

1.7 Risk

1.7.1 DD has not sufficiently reduced or mitigated TOs risks, or sufficiently compensated via the financial package

1.7.2 As had been suggested within the S&C Relative Risk Report that informed our Business Plan[42] the relative risk position of SPT is significantly higher than our position in RIIO-T2, for a combination of regulatory, geopolitical and investment reasons.

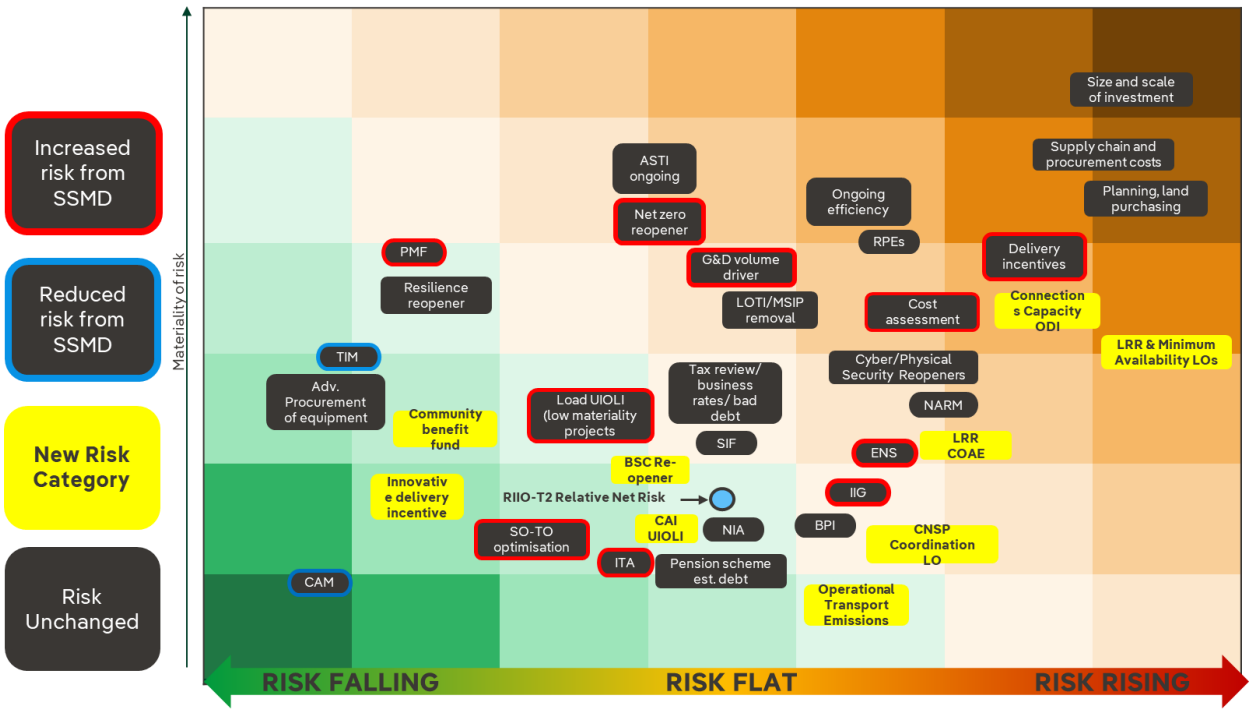
1.7.3 More specifically, there are certain areas, in particular within regulatory mechanisms (e.g. the SO:TO ODI, the Net Zero Re-opener, the cost assessment framework and various components of the LR mechanisms) which are arguably riskier in DD than their SSMD position.

1.7.4 Some of the overarching risk settings have been summarised below and are provided in more detail in a new S&C report assessing new risks relating to the DD position[43]

1. Investment risk has remained largely unchanged from SSMD, as our Business Plans by in large summarised our investment needs, but this position is far riskier than in RIIO-T2.
2. Geopolitical risk has increased, particularly with respect to potential trade barriers/constraints being proposed. Any associated constraints will have a consequential impact on supply chains as the same challenges are tackled on a global scale.
3. Regulatory risk has changed, there are areas (such as in the TIM mechanism) where Ofgem has clearly taken positive steps towards reducing risk for TOs. However, this is more than offset by the increased risk associated with other mechanisms as well as the risk associated with new mechanisms.

1.7.5 We have some ability to manage some of these risks, but many of these risks (as are set out below) are increased from RIIO-T2 to RIIO-T3, are out of our control, and are not fully diversifiable in the ET sector. As such, they are relevant for consideration within the expected return:

Figure 1-2 - T3 Relative Risk Against T2 and SSMD [44]



[42] S&C Electric. (2024). *RIIO-T3 Relative Risk Assessment*.
[43] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*
[44] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*

1.7.6 Given the overall increase in most aspects of our investment, for the reasons set out above, both between RIIO-T2 and SSMD, and indeed between SSMD and DD, we can conclude that we consider the overall risk associated with the ET sector has increased, and, where systematic (such as in the need to increase the scale of investment for ET sector/Net Zero purposes), this should be reflected in return. These systematic risks that S&C have highlighted are as follows[45]

- Scale and complexity of investment – This combines a number of risks, such as in construction, technology and resource constraints
- Land planning and access – Any impact of obtaining specific permits, conditions etc. for projects
- Supply chain and resource constraints – This could include issues associated with materials/skilled labour shortages – this can also include issues associated with geopolitical conditions (such as global/ regional tensions etc.)
- Scale and uncertainty of connections – Issues where there are connection request increases and increases in requests for integration of new generation sources

1.7.7 Ofgem is wrong to state the additional risks faced by TOs are non-systematic[46]. While we agree elements of the new and growing risks could be considered non-systematic, there remains a significant portion which are systematic and non-diversifiable:

(1) The sheer scale of required investment elevates the sector to a matter of national policy, where political intervention, regulatory approach, and national decarbonisation strategy are significant systematic risks.

(2) Large scale infrastructure projects are highly vulnerable to macroeconomic factors, supply chain and cost risks represent a significant area of systematic risk.

(3) The national mandate to deliver new infrastructure at scale and pace introduces material systematic risk, with the entire industry facing potential bottlenecks in labour supply and in the planning and consenting process.

1.8 Financeability

1.8.1 Financeability is a foundational pillar of the regulatory framework, underpinning the ability of transmission operators to deliver critical infrastructure investments at pace while maintaining operational resilience. It ensures that companies like us can access capital markets on reasonable terms, meet their financial obligations, and continue to provide reliable services to energy consumers. Equally important, it can support the principle of fairness – ensuring that both current and future generations of customers benefit equitably from the investments made today.

1.8.2 Our assessment of Ofgem's DD for RIIO-T3 indicates that the proposed approach to financeability broadly meets the immediate objective of enabling licensees to generate sufficient cash flow to service debt and maintain investment-grade credit quality. We welcome Ofgem's recognition of the importance of financeability and agree that the rationale underpinning these principles is sound. The inclusion of mechanisms such as the downward adjustment to the capitalisation rate [47] reflects a considered effort to support financial resilience in the short term, providing the required cashflows in the RIIO-T3 period to ensure credit financeability.

1.8.3 However, we wish to underscore the critical need for Ofgem to adopt a dynamic and forward-looking approach in its financeability assessments. As the energy transmission sector undergoes rapid transformation—driven by decarbonisation targets, technological innovation, and evolving consumer expectations—the regulatory framework must remain agile and responsive. The methodologies used to assess financeability must be subject to continuous review and refinement to ensure they remain robust, transparent, and fit for purpose across successive price control

[45] Annex 2.5 S&C Electric. (2025). *RIIO-T3 Relative Risk Assessment: Post DD*. para 4.12
[46] Ofgem (2025). *RIIO-3 DD – Finance Annex, para 3.62*
[47] Ofgem (2025). RIIO-3 DD – *Finance Annex, para 5.8*

periods. We set out our considerations on this point below however *further analysis is set out in detail in Annex 2.8*:

- While the current package may be deemed financeable for RIIO-T3, we have concerns about its long-term sustainability. The measures proposed in the DD, though effective in the near term, do not constitute an enduring solution. In particular, the front-loading of revenue and depreciation allowances into RIIO-T3 and RIIO-T4 risks creating imbalances in later periods, potentially undermining financeability from T5 onwards [48].Without a clear strategy to address these deferred impacts, such as the unresolved depreciation gap and the diminishing headroom in financial ratios, there is a risk that future price controls will face heightened challenges in maintaining investor confidence and securing necessary capital.
- We therefore call on Ofgem to consider the development of a more enduring financeability framework—one that balances short-term needs with long-term resilience. This could include setting a clear and consistent Baa1/BBB+ in all circumstances, signalling to investors and lenders that Ofgem will adopt a transparent approach and stepped methodology to use available cash levers to achieve credit financeability, engaging proactively with credit rating agencies to validate assumptions, and embedding principles and calculations of long-term intergenerational fairness into depreciation policy. Such measures would not only enhance the credibility of the regulatory regime but also ensure that the sector remains investable and capable of delivering the scale of infrastructure required to meet net zero commitments.
- In summary, while Ofgem's current approach to financeability represents a positive step for RIIO-T3, it must evolve to address the long-term challenges facing the sector. We will work collaboratively with Ofgem and other stakeholders to help shape a financeability framework that is enduring, equitable, and aligned with the strategic objectives of the energy transition. As outlined in Ofgem's SSMD [49], the regulator has a statutory duty to protect the interests of existing and future consumers while also having due regard to the financial viability of licensees. This dual responsibility requires a careful balancing act—ensuring that investment plans are deliverable, that companies remain financeable, and that costs are allocated fairly across generations. We have conducted analysis of Ofgem's DD proposals - where further *analysis is set out in further detail in Annex 2.8*, and have concluded on the key points[48]:

1.8.4 The proposed capitalisation rate adjustment increases the proportion of fast money in RIIO-T3 and RIIO-T4. While this may improve financial metrics to the required level in the immediate term, it does so at the expense of future periods by reducing depreciation allowances and shifting revenue forward. This front-loading weakens the financial position of SPT in T5 and beyond.

1.8.5 Our analysis indicates that under both Moody's and S&P's methodologies, key financial ratios fall below investment-grade thresholds in future price control periods. Specifically, S&P's core ratios do not meet 'BBB+' requirements in T5 and T6, and Moody's sub-factor scores deteriorate beyond RIIO-T4. These findings are detailed further in *section 1.9.1* further below. The weakening of credit metrics poses a risk to the sector's ability to attract capital, particularly in the context of increasing investment demands to meet net zero targets.

1.8.6 The capitalisation rate adjustment does not resolve the existing depreciation under-recovery. Instead, it defers the issue to future regulatory periods, compounding the challenge of maintaining financeability over the long term. Without a mechanism to address this gap, future consumers may face higher charges, undermining the principle of intergenerational fairness.

[48] Annex 2.8. NERA. (2025). *Long-term implications of Ofgem's T3 DD capitalisation rate adjustment proposal*. *Page 2*

[49] Ofgem (2024), 'RIIO-3 Sector Specific Methodology Decision – Finance Annex', para.1.12

1.8.7 NERA has modelled a wide range totex sensitivity, which shows that the results discussed above and ones that will be discussed in subsequent sections are not materially sensitive to the totex level [50]. This therefore shows the results have a strong basis and are not materially impacted by changing assumptions.

1.9 Credit rating & Cash Measures

1.9.1 We acknowledge that, under the parameters set out in Ofgem's DD for RIIO-T3, the notional credit rating outcome of Baa1/BBB+ reflects a specific regulatory intervention—namely, the capitalisation rate adjustment to 85%. This adjustment has served as a short-term lever to enhance cash flow metrics and support investment-grade credit quality in the immediate term. However, while this mechanism has delivered a financeable position for RIIO-T3 (and under Ofgem's modelling assumptions, RIIO-T4), it does not constitute a sustainable solution to the broader challenge of long-term financeability. While Ofgem may argue that any emerging financeability issues can be addressed prior to any future price controls, such as T5, this overlooks the structural nature of the problem. In practice, remedying these issues retrospectively would be extremely difficult—if not impossible—without undermining regulatory predictability and investor confidence, both of which are essential for securing long-term financeability.

1.9.2 The reliance on revenue advancement measures creates a temporary uplift in financial ratios that masks the deferred issues. As the regulatory cycle progresses into T5 and beyond, these vulnerabilities become increasingly pronounced, with key credit metrics deteriorating and headroom eroding. This trend is especially concerning given the scale of investment required to meet net zero targets through 2045, which will demand sustained access to capital and robust financial resilience. Analysis *is set out in further detail in Annex 2.8,* however key points include the following [5148]:

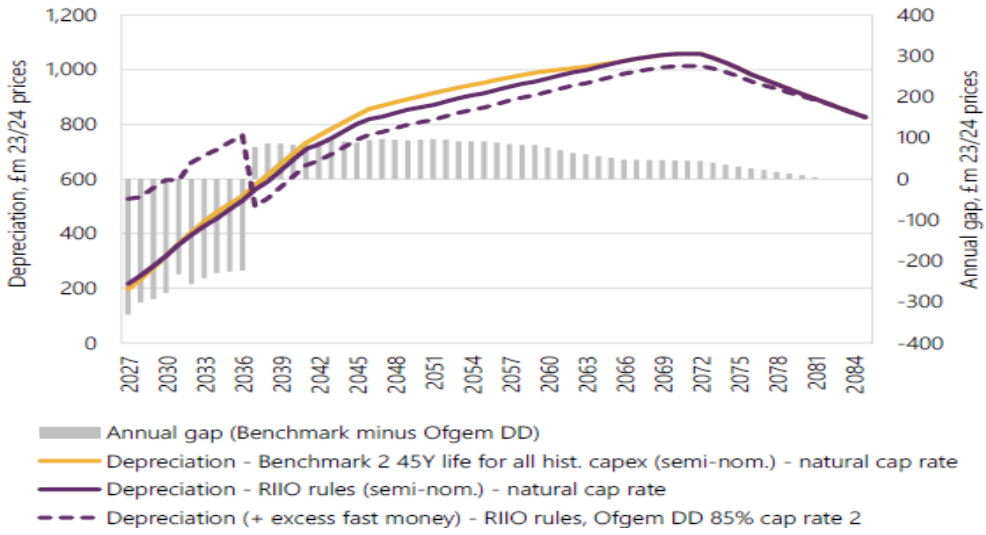
- While Moody's sub-factor scores meet the Baa1 threshold in T5, the margin is minimal, leaving little room for adverse movements. From T6 onwards, as capital expenditure and RAV growth taper, Moody's rating is retained—but cash-based ratios such as FFO/debt and RCF/debt fall below investment-grade thresholds. This creates a latent risk, particularly if Moody's revises its methodology or places greater emphasis on cash metrics in future assessments.
- Our core ratios under S&P's methodology fail to meet the 'BBB+' threshold in T5 and T6, primarily due to the substantial front-loading of depreciation and fast money. These ratios remain weak until the mid-2050s, indicating a prolonged period of financial strain that could adversely affect credit ratings and investor sentiment. S&P's supplementary ratios also have a similar impact, where FFO/ cash interest and EBITDA/Interest deteriorate from T5 onwards.
- The financeability position in T5 and beyond stands in stark contrast to the headroom created in RIIO-T3 and RIIO-T4 through the capitalisation rate adjustment. This divergence underscores the temporary nature of the current solution and highlights the need for a more balanced and enduring approach that does not rely on short-term revenue acceleration.
- Under Ofgem's proposed capitalisation rate reduction, our estimates a cumulative depreciation shortfall of approximately £0.3 billion (based on 2023/24 prices) over RIIO-T3 and beyond. This figure is derived using Benchmark 2 of economic depreciation,

[50] Annex 2.8. NERA. (2025). *Long-term implications of Ofgem's T3 DD capitalisation rate adjustment proposal*. *Page 3*

[51] Annex 2.8. NERA. (2025). *Long-term implications of Ofgem's T3 DD capitalisation rate adjustment proposal*. Page 7

which assumes a consistent 45-year asset life applied to all historical capital expenditure. The shortfall represents a material risk to future revenue adequacy and cost recovery. If unaddressed, this gap would increase to £3.0 billion (based on 2023/24 prices), T5 onwards. NERA tested the results against high and low totex scenarios, showing the results are unaffected. See below the various scenarios of depreciation revenue based on NERA's analysis for SPT:

Figure 1-3 - Scenarios for Depreciation Revenue [52][48]



Stochastic Risk Modelling

1.9.3 Stochastic risk modelling is a power technique used to simulate and assess financial risks under certainty. It utilises probability distributions to model uncertain future events, quantifying potential shortfalls over a horizon to with given confidence levels. This has been used to model our credit rating and, Moody's and S&P metrics **Error! Bookmark not defined.**.

1.9.4 Under Ofgem DD's scenario, the notional credit profile aligns with a Moody's rating of Baa1 at the 50th percentile, indicating a moderate investment-grade standing. The corresponding average rating score of 8.2 further supports this assessment, suggesting a stable credit outlook within the Baa category, albeit at the bottom end of a Baa1 rating.

1.9.5 The likelihood of a downgrade to Baa2 is considered low due to two factors:

- The total overspend risk is effectively contained due to the presence of high sharing factors embedded with the stepped TIM. These sharing arrangements ensure that any cost overruns are partially absorbed by Ofgem, reducing the financial impact on us.
- The incentive regime presents a relatively narrow downside range, with the maximum potential reduction in RoRE expected at 0.97%.

[redacted]

1.9.7 The FFO/Net Debt for S&P averages 16% over RIIO-T3 at the 50th percentile, exceeding the BBB+ threshold of 9%. This metric remains robust throughout RIIO-T5, with a 2% headroom above the threshold in 2031. *Further analysis can be found in detail in Annex 2.9;* however, the modelling of the rating and ratio can be seen below [53]:

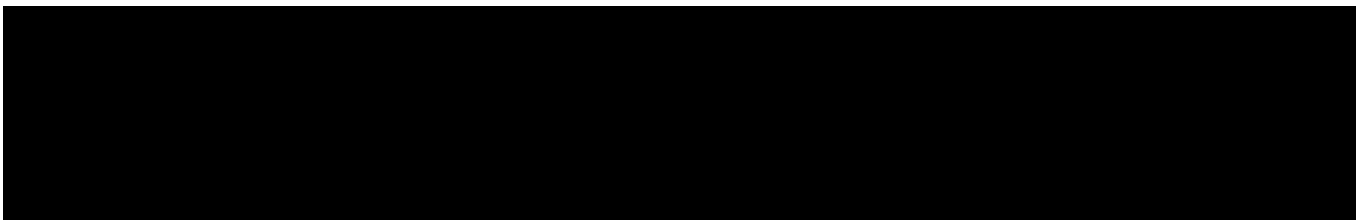
[52] Annex 2.8. NERA. (2025). *Long-term implications of Ofgem's T3 DD capitalisation rate adjustment proposal*. Page 4

[53] Annex 2.9. NERA. (2025). *Financeability Analysis for Scottish Power Transmission over RIIO-T3*. Page 12

Figure 1-4 - Stochastic Risk Modelling of Moody's Rating and FFO/Net Debt (S&P)

1.9.8 Assessing Moody's scenarios, A potential downgrade to Moody's Baa2 rating could be triggered if either of the following key financial metrics deteriorates beyond threshold levels:

- The AICR falls below <1.4x
- The FFO/ND to < 11%



1.9.10 This indicates that while the credit profile remains resilient under base-case assumptions, it becomes more vulnerable under adverse scenarios.

1.9.11 In addition to these metrics, the Capex-to-RAV ratio plays a critical role in credit assessment. According to Ofgem's regulatory assumption, the ratio is capped at a level consistent with a sub-rating of B when exceeding 30%, which helps contain rating pressure.

1.9.12 However, if the Capex/RAV ratio is assessed using Moody's standard methodology, which has scope to apply a stricter criterion, the credit outlook deteriorates more sharply.

- A downgrade to Baa3 could occur as early as 2027 under the 75th percentile scenario.
- By 2031, under the 95th percentile, the rating could fall to Ba, entering sub-investment grade territory.

1.9.13 This highlights the sensitivity of the credit rating to both financial performance and methodological assumptions, underscoring the importance of maintaining disciplined capital expenditure and robust cash flow metrics.

1.9.14 Figure 1-5, below, shows all the various risk models for Moody's ratios with the different confidence intervals [54]. *Further analysis can be found in detail in Annex 2.9*.

[54] Annex 2.9. NERA. (2025). *Financeability Analysis for Scottish Power Transmission over RIIO-T3*. Page 13

1.9.15 NERA have also modelled the DD package but using a CoE that would deliver an investable package, aligned with our business plan submission [55]. This scenario would ensure we remain within Baa1 in all probabilistic outcomes (assuming the Capex/RAV is capped at B), with risk weighted toward achieving a midpoint Baa1 rating, as opposed to the bottom end in the modelled scenario above. *Further analysis on the investable package can be found in detail in Annex 2.9*.

1.10 Fair bet for investors and RoRE

1.10.1 As we set out in our Business Plan, one of the key components of an investable financial package is the need for investors to perceive the return and risk they take to be a "fair bet". This encompasses wider implications than merely a risk-reflecting CoE. If an investor perceives the CoE to be broadly consistent with risk reflection (e.g. is proportional for the risks they take) but the underlying policy mechanisms mean that there is not a symmetry between potential rewards and potential risks, then ultimately the financial package may still not be investable.

1.10.2 We can capture the risks associated with each ODI in the round, but in this response, we set out two views of ODI impacts on RoRE

(1) Like in our Business Plan we set out a max/min view of ODIs[56] (with the exception of TIM and ASTI where we made specific assumptions)

(2) Detailed assumptions which we treat as our "expected" reward or penalty. Netting off expected penalties/rewards gets us from the DD CoE (of 5.64% on a 55% notionally geared level) to an "expected return".

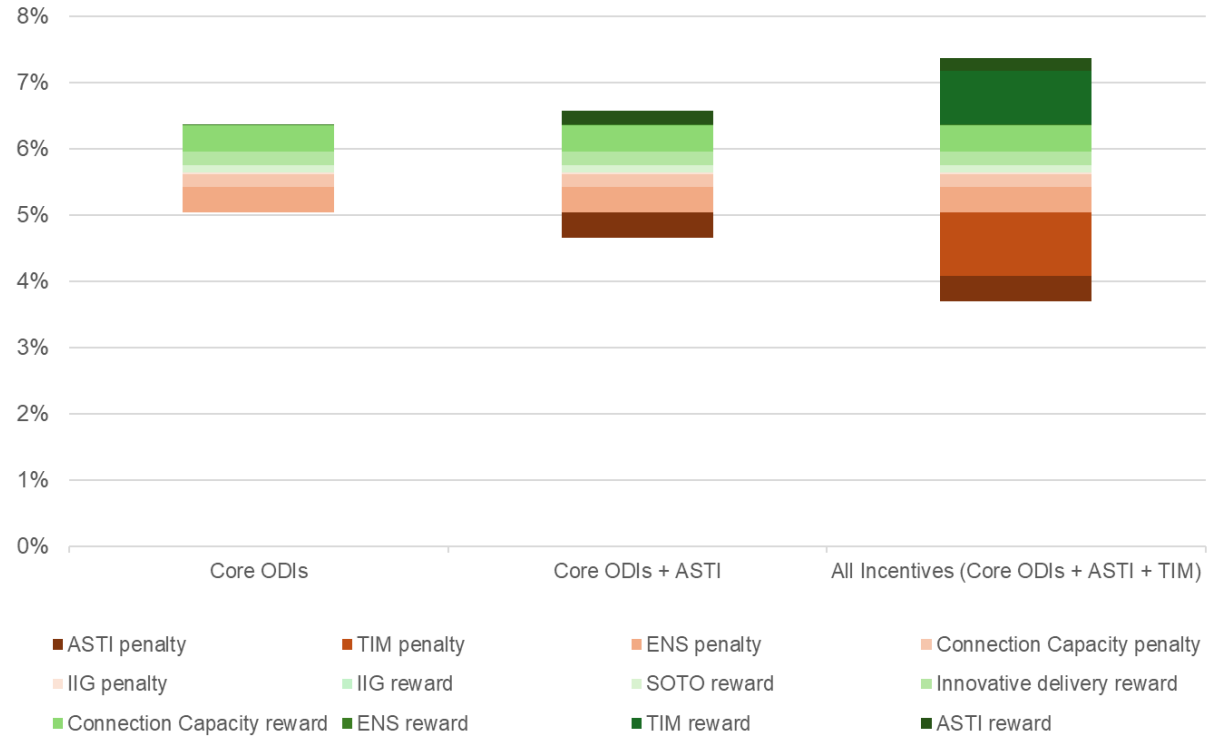
Max/min view

1.10.3 On a max/min view, where we take the max penalty and max reward for each ODI[57] we estimate a more symmetrical view than was the case in the Business Plan, which is encouraging, however, we estimate a net negative position still, implying an "expected return" which is still below our CoE. In line with the penalties/rewards set out in Draft Determination, and taking views of the

[55] Annex 2.9. NERA. (2025). *Financeability Analysis for Scottish Power Transmission over RIIO-T3*. p14
[56] On ASTI and TIM we make specific assumptions on both the max/min view and the expected view. We also do not make an assumption on CSNP-F due to the uncertainty around the application of this ODI.
[57] Same as above.

ASTI application where we only apply a fifth of ASTI is used this to give an implicit average position[58], we estimate the following expected returns:

Figure 1-6 - Max reward and max penalties (exc ASTI and TIM) in addition to DD CoE



1.10.4 As can be identified above, depending on whether we use simply core ODIs (which has a positive skew of around 13bp), core ODIs + ASTI (negative skew of around 4bp) or all incentives (negative skew of 20bp) largely impacts our view of fair bet. Therefore, even if we were to use the pro-rated scenario in isolation (using all incentives), our expected return would be lower than the DD CoE under these assumptions. However, in order to provide assumptions which are closer to what we expect of our performance (and therefore allow a more realistic view of expected RoRE impacts) we provide the expected view below to highlight the RoRE impact of ODI expected performance.

Expected view

1.10.5 Given the assumptions that we set out below, we expect a decrease in the return against the DD position, as investors must capture their expected rewards/penalties into their view of returns for their risk.

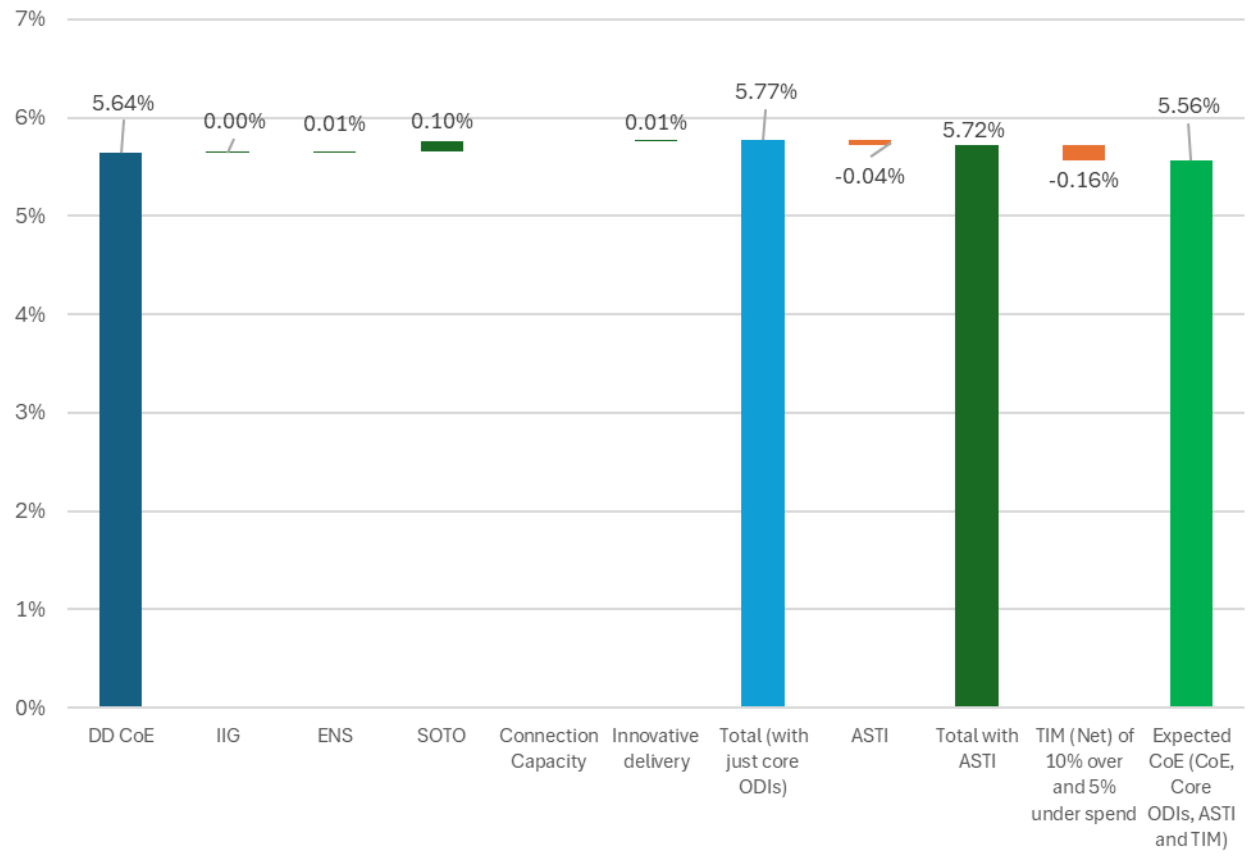
1.10.6 The graph below works based on the following assumptions to get to an "expected position" on each of the ODIs:

- IIG: RIIO-T2 average performance applied to RIIO-T3 Incentive
- ENS: RIIO-T2 Average performance applied to RIIO-T3 incentive.
- SOTO: RIIO-T2 average performance
- ASTI EGL1: Latest P50 delivery date
- ASTI DWNO: Baseline delivery date plus 6 months

[58] This is a more conservative view than our Business Plan, which used all applicable ASTI in the RoRE, and therefore gets us to a less negative position, implying that the incentives are more symmetrical (though still with more penalties than rewards) than if we had used the Business Plan method.

- Connection capacity: £0 as assuming on time delivery.
- Innovation: based on Distribution Incentive actual reward as a % of max reward then applying the same % to our max reward.
- TIM: netting of the 10% overspend position and 5% underspend position based on an assumption of potential risk

Figure 1-7 -Ofgem DD CoE, Expected Rewards/Penalties of ODIs and Resulting Expected CoE



1.10.7 As can be identified, in both views we can identify that expected penalties outweigh expected rewards and so our expected return taking these incentives into account expected performance remains lower than the DD proposed CoE. Ofgem should therefore further consider the genuine symmetry of incentives to maintain the "fair bet" principle.

1.10.8 Further, both the range of outcomes and the expected position based on our strong RIIO-T2 performance to date suggest there is insufficient potential to enhance returns in RIIO-T3. This must be resolved to ensure an investable, 'fair-bet' regulatory and financial package in RIIO-T3, this is set out further in Chapter 5 - Incentives.

1.11 Sufficient cashflows to make debt repayments

1.11.1 We agree with Ofgem's DD approach on addressing the need for an efficient notional company to generate sufficient cashflow to meet its debt obligations. However, we would expect Ofgem to consider the outcome of the approach and the long-term impact on the sector beyond the cashflow challenge during the current regulatory period.

1.11.2 We believe that establishing cashflows at an optimal level is crucial for the successful operation of a business for customers' satisfaction and in achieving sustainable growth and expansion and

we are also convinced that a more enduring approach by Ofgem on cashflows would support the goal.

Table 1-3 - Comparison of Key Financial Ratios (Moody's) Rolling Forward DD Financial Package into Long-Term [59]

Cashflow metrics	RIIO-T3	RIIO-T4	RIIO-T5	RIIO-T6	RIIO-T7
AICR	1.77	1.71	1.71	1.71	1.71
Gearing	55.00%	55.00%	55.00%	55.00%	55.00%
FFO/ND	16.10%	12.40%	8.90%	9.30%	9.90%
RCF/ND	13.70%	9.90%	6.40%	6.90%	7.40%

1.11.3 As discussed in *section 0*, cashflows remain sufficient to make debt repayments due to Ofgem adjusting the capitalisation rates as a financial lever by reducing bucket two to 85%. We deem this as a short-term solution. Whilst the cash flow metrics remain strong in RIIO-T3, it is evident that the FFO/Net Debt and RCF/Net Debt deteriorate as move into RIIO-T4 and beyond. This suggests that as we move into subsequent price controls, strong liquidity which be adversely affected. A weakened FFO/Net Debt means that operating cash flows are small relative to debt, implying that beyond RIIO-T4 there will be a greater reliance on refinancing and higher risk in cashflow.

1.11.4 Due to required cash measures in RIIO-T3, cash flows are sufficient to make debt repayments for this price control period. However, beyond this, we believe that cash from operations is insufficient, potentially compromising debt repayment capacity and strained cash flow. In return this will put pressure on credit ratings and reduce financial flexibility. Investor confidence will likely decrease in subsequent price control periods too as reduced credit worthiness may deter and undermine investors.

1.11.5 In summary, we welcome the cash measures adopted as part of the Draft Determination, which suggest we will have sufficient cashflows to meet debt repayments. However, it would be appropriate for Ofgem to consider the longer-term impact of financeability decisions.

1.12 Cost of Equity (CoE)

1.12.1 Within any price control, to simulate a competitive market, the regulator should ensure that the companies, while not being able to make excessive returns, should still be able to make a fair allowed return aligned with the level of risk. Overall, in CoE, the DD position is higher than was the case in the SSMD (5.64% compared to 5.00% respectively), this is encouraging and shows Ofgem going in the right direction in its estimation of the required financial package. However, there is still further to go in getting to an investable CoE for the TOs, and there are still issues with the way that the capital asset pricing model (CAPM) parameters have been estimated.

1.12.2 As we have expressed in Table 1-1, we do not believe that Ofgem has set out a fair return given the level of risk, and believe, based on evidence that we have identified that a return in excess of 6% on a 55% notional gearing basis is empirically justified. Additionally, as we have discussed in Section 1.1, we do not believe Ofgem has properly considered the cross-checking evidence/methodologies that we set out in our Business Plan[60] meaning that Ofgem has not had regard to relevant considerations which it ought to consider.

1.12.3 These cross-checks justify a far higher CoE than either Ofgem's own estimate, or Ofgem's cross-check range. The key points that we note in this section for CoE are as follows:

1.12.4 The CoE should be higher, both to reflect the level of risk in the industry, but also **to ensure that we can raise the level of equity capital required for our RIIO-T3 investments. There is a credible pathway to an investable return – a CoE in excess of 6% on a 55% gearing basis:**

[59] Annex 2.9. NERA. (2025). *Long-term implications of Ofgem's T3 DD capitalisation rate adjustment proposal*. p6
[60] SP Energy Networks. (2024). *Finance Annex*. section 3.8.3

- The CoE should be tested against wider cross-checking methodologies as Frontier Economics have set out. The TMR should be set above 7%, reflecting a consistent approach at cross checking and estimating a reflective TMR.
- An increase in systematic risk on a forward-looking basis justifies the need for adjustments to the Beta to reflect this.
- There is strong evidence for a convenience premium in the risk-free rate, this is further bolstered by nominal gilts showing the current estimation of the risk-free rate is too low.

1.12.5 The cost of equity parameters that follow, and the rationale that has been followed has been informed by multiple consultant reports. For more detail on CAPM estimation, there is a NERA paper on cost of equity (Annex 2.1)[61] and US equity returns (Annex 2.3)[62], and Oxera CAPM report (Annex 2.2)[63], there are also Frontier Economics reports on cross-check evidence Annex 2.4)[64], standards of evidence (Annex 2.10)[65], and the economic principles behind the calculation of TMR (Annex 2.6)[66].

Total Market Return (TMR)

1.12.6 The TMR has been raised from 6.75% in the SSMD to 6.9% in the Draft Determination, which, though encouraging in direction of travel is not empirically sufficient. We argue this is for the following reasons:

(1) Consideration of ex ante estimation of TMR

(1)(a) In considering the ex ante estimates of TMR, Ofgem produces a 6.8% bottom estimate for its TMR range. Though in the Draft Determination, Ofgem corrects previous issues in the ex ante estimation, such as the removal of adjustments for serial correlation and COLI-CED, using ex ante in any regard is still contributing to flaws in the estimation of the TMR.

(2) Not consulting TMR cross-checks

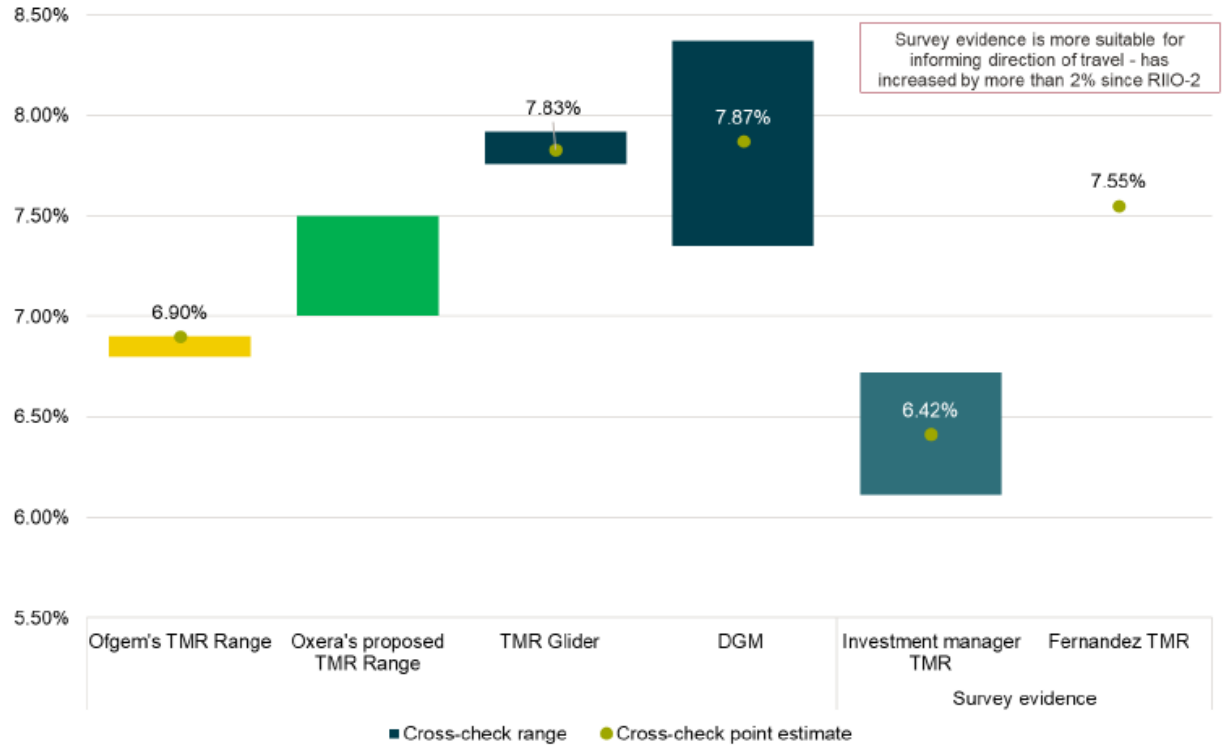
(2)(a) Ofgem has referenced a 6.92% ex post TMR (down 5bp against their SSMD ex post TMR of 6.97%). Ofgem then rounds down this 6.92% figure to 6.9%.

(2)(b) With respect to the ex post TMR, we believe that the *ex post* TMR should be around 7% still, and rounding up in line with Ofgem's *approach* of rounding to nearest 1 decimal place from ex post estimates of between 6.95%[67] and 6.96%[68].

(2)(c) There is reasonable evidence to suggest a TMR of between 7.0% and 7.5% as per TMR cross-checking methodologies. Ofgem does not, for example, seem to agree with the rationale of using TMR Glider-based estimates as a cross-checks, and do not appear to test their overall TMR range against alternative approaches to estimating TMR.

[61] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*
[62] Annex 2.3. NERA. (2025). *2.3 2025.07.24 US Allowed Cost of Equity vs Ofgem DD*
[63] Annex 2.2. Oxera. (2025). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks*
[64] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*
[65] Annex 2.10. Frontier Economics. (2025). *2.10 Frontier - Cross-checks standards of evidence - 2025.08.22*
[66] Annex 2.6. Frontier Economics. (2025). *2.6 FE-Assessing Regulators Approach to Setting the TMR*
[67] Annex 2.2. Oxera. (2025). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks*. section 3.5.
[68] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*. section 3.2.2.

Figure 1-8 - Comparison of Various TMR Cross-Checks (Updated for DD)[69]



Source: *Ofgem, Frontier Economics analysis, Oxera*

Note: *TMR Glider range represents the 20-80th percentile range over the last 24 months, which is 7.76% - 7.92%, with an average of 7.83%. All figures presented to 2 d.p.*
The DGM range represents the 20-80th percentile range over the last 24 months which is 7.35%- 8.37% with an average of 7.87%. All figures presented to 2 d.p.
We derive CPIH-real figures using the Fisher equation and a CPIH assumption of 2%.
The investment manager TMR range is constructed from the mean of all observations and the mean of observations included in Ofgem's sample at RIIO-2. The mid-point of these values makes up the point estimate.

1.12.7 It is unclear from Ofgem's assessment whether it has applied the same evidential standards to its TMR estimate as those used in the business plan. Frontier Economics developed a TMR range on behalf of the ENA, which formed the basis for our own business plan TMR range[70]. That range was grounded in clearly defined cross-checks and a transparent approach to evidence. Ofgem's methodology does not appear to apply these same standards. In particular, Ofgem, despite the arguments that have previously been set out of the implicit assumptions within the method, continues to the MARs approach as a CoE cross-check, but dismiss rationale such as the use of the DGM Glider, on the basis of the volatility in the assumptions around future dividend growth[71].

1.12.8 By dismissing the theoretical principles behind the dividend growth model, Ofgem ultimately dismisses two methodologies which (as detailed below) have both strong economic principles behind them and empirically are good at predicting regulatory returns. Ofgem ought to have regard to the DGM Glider methodology if it is going to assess TMR appropriately.

Similarity of TMR Glider and DGM in underlying principles with existing Ofgem cross-checks

1.12.9 TMR Glider and DGM are both forms of the dividend growth model, which Ofgem largely dismisses, whilst maintaining their use of MARs, which has similar underlying principles, i.e. dividend payment and expected returns can therefore be presented as a function of (inter alia) dividends and growth. Applying the logic related to the dividend growth relationship to returns,

[69] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*. Figure 15
[70] SP Energy Networks. (2024). *Finance Annex*. p22.
[71] *Ofgem. (2025).* RIIO-3 DD - Finance Annex*. Section 3.103*

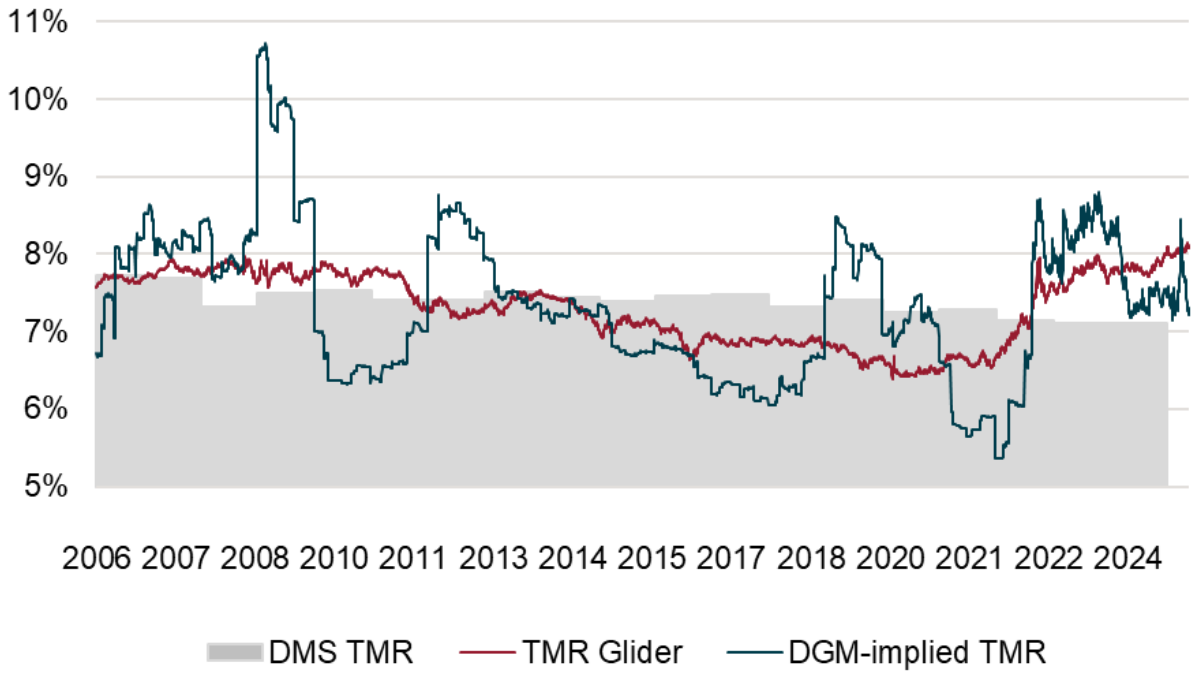
but not DGM/TMR Glider is logically inconsistent[72]. This considered, and the underlying economic underpinning TMR Glider and DGM cross-checks (presented below) mean that alongside the empirical performance of the model against long-term returns supports its use as a TMR cross-check.

1.12.10 TMR Glider accepts the underlying principles but also incorporates prevailing gilt yields, meaning that there is a consideration for current market conditions, but also the growth/dividend relationship to expected return.

The good performance of TMR Glider and DGM in prediction of regulatory return

1.12.11 In Frontier Economics' analysis, they set out how, in recent regulatory cycles, the TMR Glider has been generally a good predictor of returns. This can be identified by the following graph which highlights the historic average returns against these variants:

Figure 1-9 - Dividend Growth Model Variants and Historical Equity Returns[73]



Beta

1.12.12 We are encouraged by the fact that Ofgem has raised the equity beta above the midpoint from its SSMD position (raising the upper bound from 0.4 to 0.45). We, as we suggested in our Business Plan[74] also welcome the inclusion of European betas into the analysis, as we believe they provide a good proxy for what an investable asset beta (and therefore equity beta) could be. This considered, we do highlight the following issues which must be addressed for FD relating to the setting of an asset beta:

1.12.13 It is not clear what selection criteria Ofgem utilised when deciding on appropriate asset beta comparators

1.12.14 Ofgem has (with the exception to its position on Pennon) largely used the same subset that had been suggested for the purposes of its asset beta comparators. We would suggest that if water companies such as United Utilities and Severn Trent are to be included, then Ofgem is right to include Pennon as well. However, we suggest, given the differences in risk profile that no water

[72] Annex 2.10. Frontier Economics. (2025). *2.10 Frontier - Cross-checks standards of evidence - 2025.08.22*. section 5.
[73] Annex 2.6. Frontier Economics. (2025). *2.6 FE-Assessing Regulators Approach to Setting the TMR*. Figure 7
[74] SP Energy Networks. (2024). *Finance Annex*. section 3.3.1

comparators should be considered at all, as they are not a reasonable proxy for ET sector risk, and therefore beta. Ofgem, unlike NERA in their analysis, has not put forward an objective framework for deciding between relevant energy comparators, and so there is more scope for beta comparators to be based more on judgement than a specific criterion. For context, NERA's framework set out that supported SPEN's Business Plan is provided below:

  - Is not a water company[75]
  - More than 50% revenue and operating profit from regulated activity?[76]
  - Bid-ask spread of less than 1%
  - A high[77] trade volume
- We do not consider (based on the evidence that NERA have provided) that excluding Hera from the comparator analysis was appropriate

1.12.15 Ofgem excludes Hera on the basis of a paper from Frontier that suggests a minority of Hera's activities are in the regulated energy space. However, in NERA's analysis, they had provide detail on this (60% and 82% of revenue and EBITDA respectively related to non-water regulated activities).

1.12.16 Hera considered, removal of the water companies and consideration of non-UK[78] European comparators, estimates the following unadjusted asset betas:

Table 1-4 - Asset Beta Under Various Horizons[79]

Company		2-yr est. window				5-yr est. window				10-yr est. window		
	Avg period	Spot	2Y	5Y	10Y	Spot	2Y	5Y	10Y	Spot	2Y	5Y
Red Electrica	Elec	0.25	0.31	0.3	0.35	0.25	0.31	0.33	0.38	0.33	0.35	0.37
Terna	Elec	0.26	0.40	0.42	0.44	0.37	0.44	0.45	0.44	0.43	0.45	0.44
Snam	Gas	0.29	0.41	0.44	0.46	0.38	0.46	0.48	0.46	0.44	0.46	0.46
Enagas	Gas	0.29	0.30	0.34	0.37	0.29	0.36	0.38	0.40	0.36	0.38	0.40
Italgas	Gas	0.29	0.38	0.39		0.34	0.39					
Hera	Multi	0.46	0.54	0.54	0.45	0.50	0.52	0.50	0.44	0.45	0.45	0.43
Average		0.31	0.39	0.41	0.41	0.36	0.41	0.43	0.42	0.40	0.42	0.42
Average (exc Hera)		0.28	0.36	0.38	0.40	0.33	0.39	0.41	0.42	0.39	0.41	0.42

1.12.17 As can be identified, this gets to a non-adjusted asset beta range at the 10-year estimating window of between 0.4-0.42 (or 0.39-0.42 without Hera), markedly higher than the range proposed by Ofgem (0.3-0.45).

1.12.18 We still believe that there should be an adjustment made considering forward-looking asset risk, and do not believe that the arguments that Ofgem made in the DD Finance Annex sections 3.63 and 3.65 detract from the rationale for making a specific asset beta adjustment

1.12.19 As we set out in our Business Plan, due to the inherent risks associated with the scale and complexity of our investment (see detail in our Finance Annex section 2.3) there should still be an upward adjustment in our asset beta to consider forward-looking risk. In its DD Finance Annex, Ofgem suggested that it was not clear on how this could be incorporated into the CAPM

[75] NERA. (2024). *Cost of Equity for RIIO-T3*. Section 5.2.2.
[76] NERA. (2024). *Cost of Equity for RIIO-T3*. Table 5.4
[77] *For this reason, Elia, REN, Transelectrica and Fluxys were excluded from NERA's original comparator set*
[78] *Implicit, therefore NGET is not included.*
[79] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*. Table 4.3

theoretical framework.[80] While we acknowledge that CAPM rests on the assumption of rational expectations, it is not clear that the (inherently historic) asset betas have entirely considered the forward-looking risks we face, and so, without the need to change the CAPM mechanism for estimating expected CoE, the asset beta should be adjusted directly (we set out this logic in further detail in the asset beta section of our Finance Annex p21).

1.12.20 Considering the evidence provided above in NERA's analysis, and the forward looking asset risk adjustment which we suggest would reflect the significantly increased capex risk, and historic precedent, that the asset beta would be between 0.40 and 0.45[81].

Risk-Free Rate

1.12.21 We acknowledge that the RFR has been updated to reflect changes in the ILG rates between the SSMD and the DD estimation periods. We also acknowledge the update (slight reduction) to the RPI- wedge, set out within the "RIIO GDT3 Allowed Return on Equity Summary File DD_Jun25" model, to around 0.10 percentage points[82]. We have however identified the following issues with Ofgem's assessment of RFR which leads to a far lower RFR and therefore a lower estimated CoE:

- Ofgem does not consider convenience premia despite the previous evidence set out by Oxera[83], this reduces the estimated RFR from only ILGs

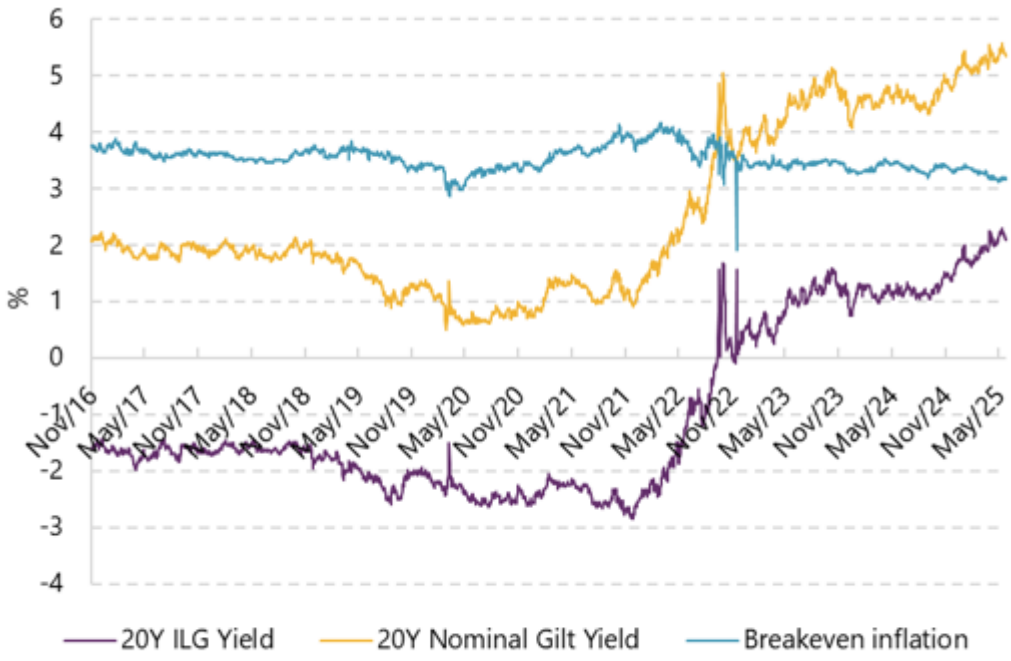
1.12.22 To estimate an appropriate adjustment for convenience premia, in their latest report on CoE for the ENA[84] Oxera employ an average of 9.5 and 14 year gilts[85] and AAA corporate[86]10+ and 10-15 year indices[85] and deduct the 9.5 and 14 year gilts to calculate an implied convenience premium. By not setting out a specific adjustment for convenience premia, along the lines set out by Oxera, Ofgem specifically produces a downward biased estimate of what a reasonable risk-free rate, consistent with economic principles would be.

- Ofgem rejects the rationale behind the use of CPIH adjusted nominal gilts[87]. Nominal gilts are posited as opposed to ILGs due to elements which do not directly account for the inherently high breakeven inflation (as below) which, without specific adjustment, biases the expected RFR downwards.

1.12.23 The rejection of nominal gilts in Ofgem's analysis mainly rests on the idea that the CMA contained evidence on nominal gilts in RIIO-T2 and provides a lack of due consideration to ILG yields highlighting implausibly high breakeven inflation (as below).

[80] Ofgem. (2025). *RIIO-3 Draft Determinations - Finance Annex. Section 3.65.*
[81] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*. para 4.3
[82] RIIO GDT3 Allowed Return on Equity Summary File_DD_Jun25*, tab 'One-Off Wedge' cell G11, and confirmed in Ofgem's response to DDQ "SPEN36".*
[83] Oxera. (2024). *RIIO-3 cost of equity—CAPM parameters*. Section 2.1
[84] Annex 2.2. Oxera. (2025). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks. Section 2.1.5*
[85] 5 year average
[86] The higher the credit rating, the less theoretical risk of default, and therefore AAA corporate bonds are closest viable proxy for a riskless asset which is not a government bond (gilt in UK context).
[87] *This was utilised in our Business Plan RFR upper estimates.*

Figure 1-10 - Gilt Yields (Index-Linked and Nominal) highlighting breakeven inflation (3.3% relative to long-term inflation expectations of 2.2-2.6 per cent)[88]



Source: NERA analysis of Bank of England data.

1.12.24 The table below presents the DD against feasible alternatives to the risk-free rate. As can be established, the risk-free rate Ofgem presents is still insufficient to proxy a genuinely risk-free rate of return.

1.12.25 The CMA in previous regulatory appeal processes in the water sector highlighted the issues of (implicitly) using ILGs in isolation:

> *"We note that evidence provided on both the presence of a convenience yield within ILG yields and on market RFRs with different borrowing and lending rates suggest that the appropriate RFR for our CAPM is likely to sit above the ILG yield. On this basis of this evidence, we consider it unlikely that the yield on ILGs is a perfect representation of a theoretical RFR (or the average market participant rate in the Brennan approach). We consider that, on balance, it is likely that the RFR appropriate for a range of relevant investors sits above the return available from ILGs, but below the level suggested by the return on AAA bonds"*[89]

1.12.26 Ofgem should either adjust its existing estimate by convenience premia in order to reasonably still maintain use of index-linked gilts as the basis of the risk-free rate, or, to directly correct for the issues associated with infeasibly high breakeven inflation should directly adjust nominal gilts by CPIH. Ofgem's current proposal is not a reasonable estimate of risk-free rate:

Table 1-5 - Comparison of RFR Estimates

DD RFR	RFR and Convenience Premia Adjustment	Nominal Gilts (Adjusted for CPIH)
2.01%	2.25%	2.73%-3.13%[90]

[88] Annex 2.1. NERA. (2025). *2.1 250820_RIIO-3_cost_of_equity_response_DD_NERA_Final*. Figure 1.
[89] Competition and Markets Authority. (2021). *Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations - Final report*. para. 9.264
[90] This depends on assumption made on CPIH

1.12.27 All of these CAPM component changes considered (to TMR, RFR and equity beta), we suggest that the CoE should be raised beyond the DD estimate to ensure that we maintain investability and can raise the levels of equity capital that are required to make our RIIO-T3 investments to foster net zero achievement for GB, and to facilitate economic growth.

1.13 Cost of Debt (CoD)

1.13.1 We agree with Ofgem's decisions to amend the CoD allowance methodology to better reflect the significant market movements since RIIO-2, via the adoption of a RAV weighted mechanism. However, we continue to be of the view that the calibration and estimation is the most important part of the process in setting a fair allowance. We support Ofgem's position to use ET and ED companies in the calibration exercise for ET, given there are only three Transmission Owners (TOs), and NGET would have an outsized influence on the calibration without inclusion of ED companies.

1.13.2 We are broadly comfortable with Ofgem's estimation of efficient debt costs and calibration of the index, however with a couple of issues in the calculation of the calibration adjustment:

(1) Ofgem uses flat interest rate iBoxx/SONI instead of forward curve, underestimating market expectations of interest over RIIO-3.

Ofgem sets the calibration based on a downside interest rate scenario of +1%, but over RIIO-2 actuals are +2.5% higher than forecast, suggesting +1% is insufficient to capture interest rate risk

Calibration

1.13.3 We note the 45bp calibration adjustment with respect to the 14-year RAV weighted trailing average for ET and welcome Ofgem's assessment of the need for adjustment to obtain efficient cost. While we agree on the principle behind much of the baseline CoD, we are of the opinion that the required calibration adjustment may be understated based on the modest +/-1% scenarios relative to variation to forecast over RIIO-2 of >2%. Hence Ofgem should consider using forward rates instead of the flat interest rate iBoxx/SONI.

1.13.4 Ofgem sets the calibration adjustment (45bps) based on underperformance under a +1% interest rate scenario, which relies on flat interest rate forecasts for iBoxx/ SONIA. The below issues have been identified with this approach:

(1) Ofgem's reliance on flat rates as opposed to forward rates reflecting market expectations of interest over RIIO-3:

(1)(a) Using forward rates results on an average iBoxx A/BBB interest over RIIO-3 of 6.93%, 83bps higher than Ofgem's flat 6.10%

(1)(b) Given that adding +1% to interest rates increased the ED&ET sector underperformance by c.15bps, relying on forward rates which show a similar delta could worsen underperformance by an additional 10-15bps, resulting in a higher uplift of 55-60bps required.

(2) Ofgem's high/low-interest rate scenarios do not sufficiently account for potential downside scenarios:

(2)(a) Ofgem sets the calibration based on a downside interest rate scenario of +1%, but over RIIO-2 actuals are +2.5% higher than forecast, suggesting +1% is insufficient to capture interest rate risk.

(2)(b) As per above, a higher interest rate sensitivity (e.g. 2% or 2.5%) could lead to higher underperformance of 15-20bps, resulting in a higher uplift of 60-65bps required.

Additional cost of borrowing:

1.13.5 In RIIO-T3 DD, Ofgem proposes additional cost of borrowing (ACB) of 0.19% which is less than the SSMD working assumptions of 0.25%. Added to the proposal is to merge the Cost of carry and liquidity/RCF cost into a single additional borrowing allowance called the liquidity allowance on the basis that the size of cash balances and RCFs are negatively correlated and likely to be driven by common casual factors[91].

1.13.6 The consolidated cost of carry allowance and liquidity/revolving credit facility allowance for RIIO-T3 was set at 13bps based on RIIO-T2 data. In our opinion the cost of carry allowance based on Ofgem's adopted approach is insufficient as it substantially understates the required cost of carry for the ET sector. Considering the significant growth in RAV in RIIO-T3, we would require a higher cash/debt ratio to ensure sufficient liquidity level in achieving financial resilience required to pre-finance the significant growth in RIIO-T3 RAV and new debt issuance. In agreement with NERA analysis an estimate of combined value of 41bps for ET sector for these specific components of ACB must be properly considered by Ofgem.

1.13.7 Additionally, we would argue that Ofgem should consider allowing cost of draw down as an addition to the liquidity cost allowance[92], given that companies draw down facilities to finance the operational activities. Therefore, an assumption of 0% by Ofgem is inappropriate and should be reviewed. In addition, the scope of commitment fee should be broadened to include other incidental cost directly attributable to the RCF as part of the cost of maintaining RCF.

1.13.8 This position is supported by evidence and analysis set out in NERAs "Liquidity Cost & Cost of Carry Allowance at RIIO-ET3" report.

[91] Ofgem. (2025). *RIIO-3 DD - Finance Annex*. para 2.55.
[92] Annex 2.11. NERA. (2025). *2.11 250820_ENA_Liquidity+Carry_Draft_sent_clean_Final*. p11

FINANCE QUESTIONS

FQ 1 Do you agree with our approach to estimating efficient debt costs and calibrating the index?
We agree with Ofgem's decisions to amend the CoD allowance methodology to better reflect the significant market movements since RIIO-2, via the adoption of a RAV weighted mechanism. However, we continue to be of the view that the calibration and estimation is the most important part of the process in setting a fair allowance. We support Ofgem's position to use ET and ED companies in the calibration exercise for ET, given there are only three Transmission Owners (TOs), and NGET would have an outsized influence on the calibration without inclusion of ED companies.

We are broadly comfortable with Ofgem's estimation of efficient debt costs and calibration of the index, however with a couple of issues in the calculation of the calibration adjustment:

1. Ofgem uses flat interest rate iBoxx/SONIA instead of forward curve, underestimating market expectations of interest over RIIO-3.
2. Ofgem sets the calibration based on a downside interest rate scenario of +1%, but over RIIO-2 actuals are +2.5% higher than forecast, suggesting +1% is insufficient to capture interest rate risk

FQ 2 Do you agree with our proposal to use a combination of iBoxx GBP A and BBB 10+ non-financial indices rather than the iBoxx GBP Utilities 10+?
On balance we are comfortable with the switch back to the iBoxx A GBP A and BBB 10+ non-financial indices. While the underlying index is important, we view the calibration exercise as the key part in ensuring our efficiently incurred debt costs are fully remunerated. The wider base of debt costs will mean means that the index, theoretically, is less susceptible to overreliance on the stability of one sector.

FQ 3 Do you consider our proposed notional ILD assumption to be appropriate?
We have not undertaken analysis to estimate the forecast sector average ILD proportion, however we agree a reduction to 10% would fulfil a dual purpose. First aligning with the expected sector average ILD proportion, as Ofgem has stated in its DD. Second, improving financeability, helping achieve the required cashflow during the RIIO-T3 period and reducing equity issuance costs.

FQ 4 Do you agree with our approach to setting the additional cost of borrowing allowances?
We do not agree that certain aspects of additional costs of borrowing (ACB) have been fully incorporated by Ofgem's in its estimations.
In particular, we suggest that Ofgem has significantly underestimated the cost of carry and liquidity and therefore are very likely to have underestimated the overall additional costs of borrowing.
Ofgem's approach is likely to have understated cost of carry as the difference between assumed cash deposit rate[93] of 1.45% and forward-looking data of around 3.00% (over RIIO-T3). Ofgem also assumes the RIIO-T2 cash/debt ratio to be broadly representative of RIIO-T3 despite RAV growth mandating a higher cash/debt% (around 12%)[94]. Given these significantly increased RAV requirements, and the more representative forward-looking cash rate, NERA estimate a significantly higher cost of carry than Ofgem's assumption.
On liquidity, Ofgem does not make a specific allowance for the costs associated with draw down which would be expected costs within normal operating companies associated with meeting working capital requirements. These additional costs are around 3 bp, meaning a liquidity allowance should be around 5bp.
The table below sets out the overall differences between the two aspects within Ofgem's ACB estimate.

[93] Based on iBoxx
[94] Annex 2.11. NERA. (2025). *2.11 250820_ENA_Liquidity+Carry_Draft_sent_clean_Final*. p3.

Table 1-67 - Ofgem and NERA Estimations of Cost of Carry and Liquidity Allowance

Parameter	Ofgem's ET3 DD	NERA' Estimate for RIIO-ET3
Cash assumption (% debt) [A]	7.7%	12%
iBoxx-cash rate spread [B]	1.45%	3.0%
Cost of carry allowance [C=A*B]	**11bps**	**36bps**
RCF size assumption (% debt) [D]	10%	14.6%
RCF drawn-down assumption [E]	-	3.1%
Commitment fees [F]	16bps	16bps
Commitment fees for undrawn facilities [G]	2bps	2bps
Interest on drawn liquidity + utilisation fee [H]	-	2bps
Upfront arrangement, legal, agency fees [I]	-	1bps
Liquidity allowance [J=G+H+I]	**2bps**	**5bps**
Total [C+J]	**13bps**	**41bps**

FQ 5 Do you agree with our proposed treatment of inflation with respect to the allowed return of debt?

We acknowledge the rationale for continuing to use CPIH as a more comprehensive measure of inflation. Its inclusion of owner-occupiers' housing costs enhances its ability to reflect the full cost of living, making it theoretically more representative than CPI. Accordingly, we do not object to its use as the basis for actual price control indexation.

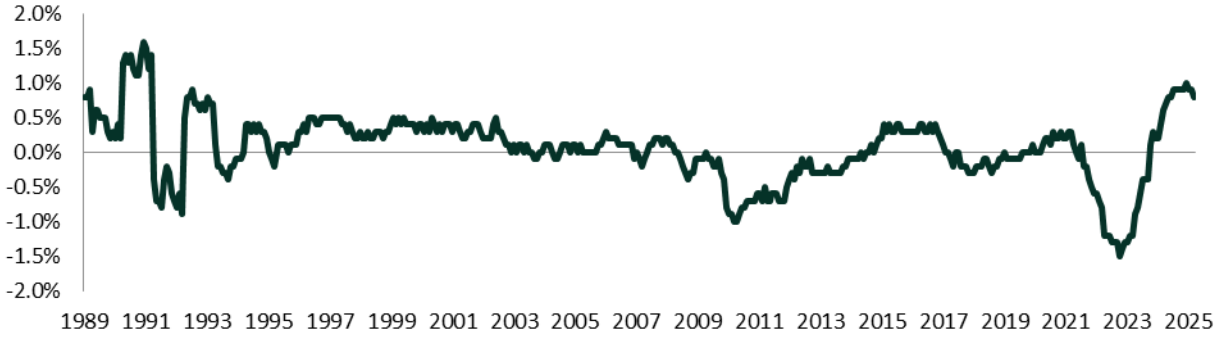
However, while we support the use of CPIH as the actual index for price control purposes, we do not agree with its use as a forecast measure—particularly over the medium to long term. To assess the validity of embedding a long-term CPIH–CPI differential into regulatory models, we commissioned Oxera to analyse the historical relationship between the two indices[95] findings show that this relationship lacks the stability and predictability required to justify a fixed wedge.

Oxera found no robust or well-evidenced basis for assuming a persistent long-run premium of CPIH over CPI. On this basis, we consider Ofgem's adoption of the OBR's assumption—that CPIH will exceed CPI by 0.4%—to be inappropriate for calculating a real cost of debt allowance. This assumption risks distorting inflation forecasts and undermining the credibility of long-term regulatory decisions.

Historically, CPI and CPIH have tracked each other closely. Historical evidence does not support the existence of a stable or predictable wedge—the observed differential between CPIH and CPI is highly variable over time, with no clear long-term trend. As illustrated below, the differential between CPIH and CPI has been highly unstable over time, frequently fluctuating above and below zero, with extended periods in which CPI has exceeded CPIH. This volatility demonstrates that the relationship between the two measures lacks the consistency required to justify the application of a fixed wedge in long-term regulatory assumptions.

[95] Annex 2.2. Oxera (2-25). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks*, pp. 27-31

Figure 1-11 - Historical outturn CPI-CPIH wedge



Source: Oxera analysis based on Office for National Statistics (ONS) data.

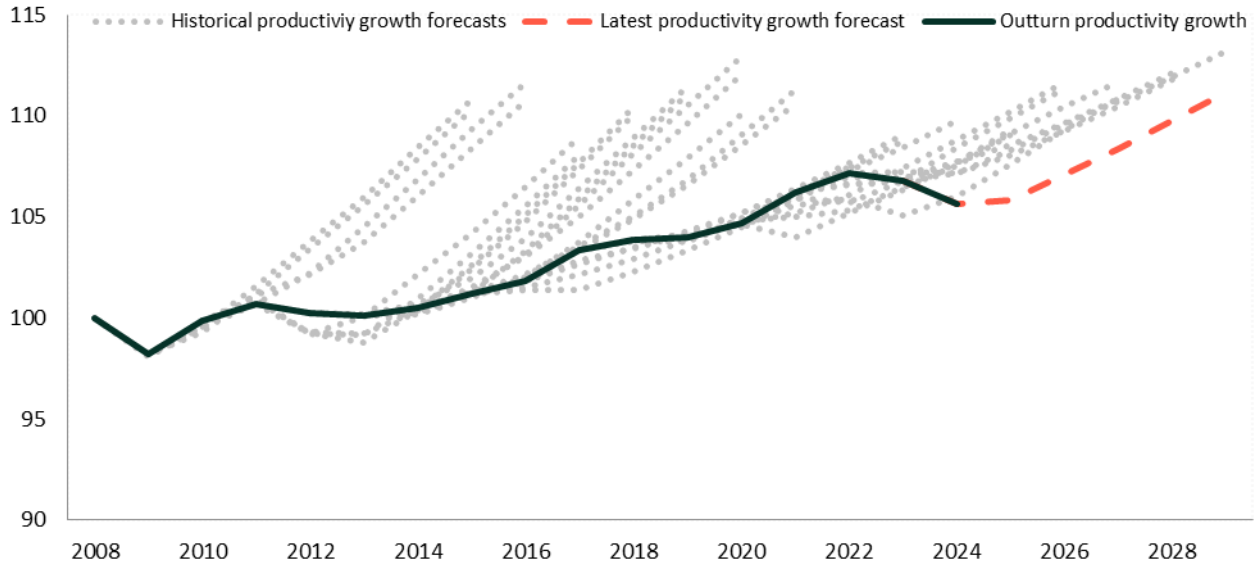
Over the past ten years, the average difference between CPIH and CPI is -0.04%, while over the past 20 years it is -0.12%. These results indicate that CPIH has not exhibited a persistent or material premium over CPI, rather that the data reflects a directionless and unstable relationship between the two indices over time. The finding above is consistent with Ofgem's own view as articulated in the RIIO-3 SSMD[96].

Furthermore, the measurement of CPIH differs from CPI by including also (i) owner occupiers' housing (OOH) costs (which represent 16% of the CPIH basket) and, (ii) council tax (which represent 3% of the CPIH basket), alongside the same components included in CPI (which account for 81% of the CPIH basket). As council tax is only a small share of the CPIH index, while OOH represents a more substantial portion, the assumptions underpinning OOH cost growth drive the long-term forecast divergence between CPI and CPIH[97].

The OBR's forecast for long-term OOH costs by growing these in line with CPI actual private rental inflation—which in the long run is assumed to grow in line with average nominal earnings. In turn, the main determinants of average nominal earnings growth, and as such the CPIH–CPI wedge, are assumed to be the GDP deflator and productivity growth, 2.3% and 1.5% respectively.[98]
However, it is challenging to forecast productivity growth accurately, with most OBR forecasts of productivity growth materially overshooting the resulting growth, as illustrated below:

[96] Ofgem (2024), 'RIIO-3 Sector Specific Methodology Decision – Finance Annex', 18 July, para. 3.56 (last accessed on 23 July 2025).
[97] Office for Budget Responsibility (2024), 'Economic and fiscal outlook', October, pp. 38–39.
[98] Office for Budget Responsibility (2024), 'Economic and fiscal outlook', October, pp. 38–39.

Figure 1-12 - Productivity growth forecasts and outturn productivity growth (2008=100)



Note: Latest productivity growth forecast is based on the March 2025 OBR Forecast
Source: Oxera analysis on historical OBR productivity forecasts

The challenge with forecasting productivity is well documented. For example, Professor David Miles—a member of the Budget Responsibility Committee—has made the following remarks to the Parliamentary Treasury committee on the gaps between forecasts and outturn results[99]. This raises a concern: the macroeconomic conditions required to sustain a 0.4% CPIH-CPI differential are not currently in place and may not emerge for some time.

As for the council tax component, the OBR states in their October 2024 forecast states[100]:

"*Our council tax forecast is informed by known referendum principles, announcements by councils, and examining trends in recent behaviour. For the years in which policy is not currently set,* ***our policy-neutral assumption is that levels will grow by 4.8 per cent***."

While this assumption may be justifiable in the near term, it becomes increasingly unsubstantiated when extended across the long-term forecast. Referendum principles and recent council behaviour provide a basis for short-term projections, but there is insufficient long-term evidence to support a sustained annual growth rate of 4.8%. This rate appears unnaturally high, particularly in the context of the OBR's March 2025 forecast, which expects CPIH to fall back to 2.1% from 2027 onwards[101]. Given that council tax comprises only 3% of the CPIH basket, applying a disproportionately high growth rate to such a small component risk introducing an upward bias to CPIH forecasts. A more balanced approach would be to align council tax growth assumptions with broader inflation trends and fiscal policy, ensuring consistency and credibility in long-term inflation forecasting.

This undermines the view of a persistent wedge between CPIH and CPI. The differential has historically hovered near zero, and the recent uptick appears to be **temporary**, likely driven by housing cost dynamics rather than a fundamental shift; in addition to the 4.8% assumption in council tax being overstated. In our view, the OBR's assumption is not only unsupported but risks distorting inflation forecasts. A more evidence-based and transparent approach is needed—one that reflects actual economic conditions rather than speculative long-term differentials.

CPI is also a more credible and transparent medium to long term forecast measure, given it is supported by a wide range of independent public data sources and anchored by the Bank of England's 2.0%

[99] UK Parliament (2024), 'Oral evidence: Economic and fiscal outlook, HC 454', Treasury Committee, 17 April.
[100] Economic and fiscal outlook – October 2024 - Office for Budget Responsibility, page 38
[101] Economic and fiscal outlook – March 2025 - Office for Budget Responsibility, tab 1.7

inflation target. In contrast, CPIH lacks a comparable forecasting base and is not targeted by monetary policy. Given the absence of a consistent historical divergence and the lack of consensus among forecasters, embedding a long-term CPIH–CPI differential into regulatory models is not justified.

In conclusion, while CPIH offers a more comprehensive measure of inflation for actual indexation purposes, its use as a forecast input—particularly over the long term—is not supported by historical evidence or current economic conditions. The relationship between CPIH and CPI has been volatile and directionless, with no consistent or material differential over time. The OBR's assumption of a 0.4% long-term wedge lacks a robust evidential basis and risks distorting regulatory forecasts. Given CPI's stronger forecasting foundation, broader consensus, and alignment with monetary policy, it remains the more credible and appropriate measure for long-term inflation assumptions in regulatory models.

FQ 6 Do you agree with the removal of the infrequent issuer allowance?
We largely agree with the removal of the infrequent issuer allowance given the scale of our investments and therefore how unreasonable it would be to proxy us against infrequent issuers for the purposes of additional borrowing costs.

We do note however that there are other aspects of additional borrowing costs which have not been sufficiently reflected within Ofgem's proposals, i.e. in cost of carry and in liquidity costs where Ofgem's estimate (as we set out in FQ4 and in section 1.13.5). While we agree with the removal of the infrequent issuer allowance, reflecting the RIIO-3 context, Ofgem needs to likewise reflect increases in other areas of ACB as a result of the RIIO-3 context.

FQ 7 Do you agree with our methodology for calculating the RFR?
We agree with the update to the baseline risk-free rate on the basis of the update to bond yields. However, without adjustment, we do not believe that these bonds reflect a proxy for a risk-free rate. In our Business Plan, we presented NERA analysis[102] suggesting that the use of nominal gilts could be appropriate to eliminate issues associated with breakeven inflation inherent to the use of index-linked gilts. We still feel that the use of nominal gilts is appropriate to avoid issues associated with ILGs.

However, as we had proposed in our RIIO-T3 Finance Annex[103], where ILGs are used as the basis for the risk-free rate, on the balance of evidence, and adjustment for a convenience premium should be considered in addition to the ILGs in order to reasonably approximate a risk-free rate. Ofgem have dismissed this within their Finance Annex[104] and argued that evidence presented by the TOs was not compelling. However, we would draw Ofgem's attention to Oxera's position as set out in their RIIO-3 DD response[105], which provides that ILGs have attributes and money-like properties that make them a poor proxy without relevant adjustments for a risk-free rate:

- The convenience premium can be argued to be relatively stable over time
- That gilts are often held for reasons of "preferred habitat" meaning that using ILGs in isolation without an adjustment of a convenience premium would not be sufficient to proxy a genuine risk-free rate
- Convenience premia are not necessarily driven by maturity of the underlying instruments – as such, not being able to observe directly a convenience premium associated with one tenor does not mean that value could not be inferred

Our convenience premia estimated by Oxera in their DD Response supporting annex (based on averaging corporate and UK Government bonds) against UK government bonds to estimate the difference in risk-free assets, gave a difference of around 24bp[106]. This would result in a final RFR of around 2.25%, based on DD data cut off dates.

FQ 8 Do you agree with our methodology for calculating the inflation wedge?
With respect to the RPI-CPIH wedge we have no immediate reservations from the SSMD methodology.

[102] NERA. (2024). *Cost of Equity for RIIO-T3*. Section 3.4.1
[103] SP Energy Networks. (2024). *Finance Annex*. p17.
[104] Ofgem. (2025). *RIIO-3 DD - Finance Annex*. para 3.29.
[105] Annex 2.2. Oxera (2-25). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks.* section 2.1.
[106] Annex 2.2. Oxera (2-25). *2.2 Oxera - RIIO-3 DD CAPM parameters and debt-based cross-checks*. Table 2.3.

FQ 9 Do you agree with our methodology change in calculating the ex ante TMR?
We agree in principle with the removal of the COLI-CED adjustment and the serial correlation adjustment to the assessment of the ex ante approach. However, we do not believe that Ofgem should be using ex ante due to its underlying assumptions in any case, and highlight that Ofgem's DD TMR still is insufficient against our cross-checks based on multiple methods which suggest a RIIO-T3 range of between 7.0% and 7.5%.

We also note that the ex post estimate of the TMR should still be 7% (see section 1.12.6(2)(b)1.12.6(2)(b)).

Given an update to the cross-checking that we proposed in our Business Plans, we would still expect this range to be 7% to 7.5% or now expect TMR to be at least[107] 7% to 7.5%[108].

It is not clear from Ofgem's analysis that it has applied a consistent or reasonable framework to obtain the TMR and by considering wider market aspects in calculating the TMR, it is entirely feasible that for future price reviews that expected TMR could reduce. However, in RIIO-T3, given the market conditions which have been proxied by alternative approaches to calculating TMR (such as the TMR Glider for example), the TMR should be higher, and at least 7%. Even where TMR has been increased from the 6.75% in the SSMD to the 6.9% in the DD, it is still insufficient against reasonable cross-checks. See section 1.12.6(2)(c).

FQ 10 Do you agree with our methodology for estimating beta?
We largely agree with the process of calculating asset beta (with equity beta stemming from this after adjustment for notional gearing) although we do have the following reservations about the basis for and final estimate of the asset beta.

- We do not believe (as we suggest in FQ11 and in section 1.12.12) that Ofgem has employed an objective comparator selection criteria)
- We maintain that flat WACC should be used as the basis of CoE for the TOs who are 55% weighted, meaning that the estimation of the beta for lower geared operators would not result in CoE being so much lower (we consider this concept further in section 1.5.4); and
- We still believe that there should be an adjustment on the basis of forward-looking risks as we do not believe that current backward-looking data analysis can estimate a fully reflective estimate of our risks in RIIO-T3 (see section 1.12.181.12.20)
- We also agree with the broad premise of degearing raw betas and then regearing to get equity betas

FQ 11 Do you agree with our proposed set of comparators which also incorporates selected European utility stocks?
We agree in principle with some of the comparators selected for the European comparator sample, however any comparator selection must be objective. We do not agree with the omission of Hera as NERA's analysis supported the view that the majority of their revenue and EBITDA comes from regulated activities.

For beta selection more specifically, we commissioned NERA[109] in our Business Plan to estimate asset betas, and as part of their selection, NERA proposed four objective criteria as follows:

- Is not a water company[110] (we would suggest however that if water companies are to be considered, it is logically consistent that Pennon is included)
- More than 50% revenue and operating profit from regulated activity[111]
- Bid-ask spread of less than 1%

[107] Frontier suggest that this should be at the top of the range, but in providing the range here we take this as is.
[108] Annex 2.4 Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*. para 10.2.3
[109] NERA. (2024). *Cost of Equity for RIIO-T3*.
[110] *NERA*. (2024). *Cost of Equity for RIIO-T3. Section 5.2.2.*
[111] *NERA.* (2024). *Cost of Equity for RIIO-T3. Table 5.4*

- A high[112] trade volume

We would suggest that Ofgem adopts a similar objective approach.

On the basis of these criterion, and updated for new data for the DD response and forward-looking asset risks, NERA estimate a reasonable asset beta range of around 0.40-0.45 (see para 1.12.20).

FQ 12 Do you agree with the conclusions we have drawn from our chosen cross-checks?
No, we do not believe Ofgem has drawn the correct conclusions on the basis of its chosen cross-checks as we posit the following

- Ofgem has broadly used its estimation of its cross-checks to conclude an investable CoE.

Ofgem in determining its CoE cross-checks, as we suggest in section 1.6.5, conclude that its 5.64% CoE (at 55%) and 6.04% CoE (at 60%) is generally investable as it is roughly in line with its cross-check estimates average of around 5.8% (see section 1.6.5), and limiting the investability test to this limited view of CoE cross-checks

- Ofgem has not considered alternative cross-check methodologies significantly

Ofgem has not sufficiently considered alternative methodologies, or the estimations put forward in the ENA's cross-check paper for CoE.

On MARs, Ofgem seems to have used the Ofwat's 2024 Price Review (PR24) analysis, and concluded a CoE based on this method of between 4.2% and 6.2%. It is not clear that Ofgem has conducted its own, more ET relevant assessment of MARs. This same cross-check methodology was assessed in the ENA cross-checks paper written by Frontier Economics and suggested a CoE range between 4.65% - 9.19%[113], or a midpoint of around 7.27%[114].

Ofgem appears to have unduly ruled out reference to hybrid bonds, and refers largely to potential issues (such as variability of the spread between debt and equity) rather than the underlying principle. We do however acknowledge that the 6.04% (60% geared) CoE from the Ofgem DD is within the bounds (clearly at the bottom end) of the hybrid bond range. We do however acknowledge that the 6.04% (60% geared) CoE from the Ofgem DD is within the bounds (clearly at the bottom end) of the hybrid bond range.

While we do acknowledge that the CoE has been raised and at the 60% notional gearing level is in line, albeit at the bottom end of our cross-checks, Ofgem has used a limited and flawed sample of methods. Using the cross-checks that Ofgem have and dismissing the hybrid bond method and the MAR evidence Frontier put forward (not withstanding infrastructure IRR and profitability as proxies) lead Ofgem to a far lower CoE cross-check range than is reasonable. Ofgem's failure to have considered the hybrid bond method and the MAR evidence leads to an unreasonable CoE and must be reconsidered by Ofgem.

FQ13 Do you agree with our treatment of risks to the ET and Gas sectors as non-systematic?
We believe this to be partially the case, however, we have pointed out that there should be an upward adjustment associated with the anomalous forward-looking asset risk for RIIO-T3, and as such proposed (supported by the NERA report on CoE we cited in our Finance Annex). Given this is an ET related growth (not in line with gas distribution or transmission sector trajectory), this should not be considered as a whole RIIO-3 issue. As suggested in NERA's CoE supporting document from our Finance Annex, Ofgem itself has acknowledged a higher beta in the construction phase associated with Hinkley Seabank. Additionally, the UR in Northern Ireland recently considered totex to RAV for the setting of a return for NI gas and suggested a contribution from this of around 0.02 beta[115].

[112] *For this reason, Elia, REN, Transelectrica and Fluxys were excluded from NERA's original comparator set*
[113] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*. section 4.4.7
[114] Annex 2.4. Frontier Economics. (2025). *2.4 FE Updated Cost of Equity Cross-Check Evidence - ENA*. Figure 1
[115] NERA. (2024). *Cost of Equity for RIIO-T3*. p40

We also continue to believe that there are risks associated with RIIO-T3, such as the scale and complexity of the RIIO-T3 investment, challenges around land planning and access, persistent supply chain and resource constraints and enduring uncertainty around connection volumes. *This is set out in more detail in Annex 2.5*[116]*.*

Ofgem is wrong to state the additional risks faced by TOs are non-systematic[117]. While we agree elements of the new and growing risks could be considered non-systematic, there remains a significant portion which are systematic and non-diversifiable:

- The sheer scale of required investment elevates the sector to a matter of national policy, where political intervention, regulatory approach, and national decarbonisation strategy are significant systematic risks
- Large scale infrastructure projects are highly vulnerable to macroeconomic factors, supply chain and cost risks represent a significant area of systematic risk.
- The national mandate to deliver new infrastructure at scale and pace introduces material systematic risk, with the entire industry facing potential bottlenecks in labour supply and in the planning and consenting process.

FQ 14 Do you agree with our proposed dividend allowance policies for the notional gas and electricity companies?

We agree with Ofgem's proposed dividend allowance policy for notional company, acknowledging the need to balance consumer value and investors' confidence, which we deemed to be a good indication of regulatory support to investors. However, we believe that Ofgem need to consider policy flexibility to ensure investors' concerns are not amplified due to dividend lock-up policy. Ofgem need to ensure that the dividend allowance policy is flexible, and with intrinsic capacity to meet the future financeability and investability need as they evolve.

The proposed dividend allowance policies allow for regular payments which we considered important for the attraction of long-term equity investment. How ever the sufficiency of the proposed dividend yield is a concern for us, as we consider the 3% dividend yield relatively low for equity investors retention.

We also believe that asset growth does not automatically translate to investors compensation, hence Ofgem's proposed policy on dividend allowance could help strike the good balance between capital appreciation and regular income to support investors perspectives and their different goals. This is in line with Oxera's position on the concept of "heterogeneity of investors".[118]

Our position on steady and regular dividend payment is in alignment with Oxera's report on RIIO-3 Risks and investability topics where "Clientele effect" was discussed to highlight the heterogeneity of investors. We draw out the below points raised by Oxera on appropriate dividend payments which Ofgem ought to consider prior to the FD:

1. Irrespective of the financial resilience measure Ofgem has in place for the networks, there should not be trade-off between investability and financial resilience.
2. There is possibility of divergence in industry expectations if there is any reduction in dividends.
3. Investors anticipations of higher dividend yield from ET companies.

FQ 15 Do you agree with our proposal not to apply the flat WACC approach?

No, we believe, as we set out in our Business Plan, that Ofgem should not deviate from the flat WACC, both for regulatory consistency and investability purposes. As we highlighted in the Business Plan, the removal of flat WACC would mean we would be subject to a roughly 20bp lower CoE in the SSMD (5.00% rather than 5.20%), and a 15bp lower CoE in the DD (5.64% rather than 5.79%).

It is not consistent with investability for CoE for the TOs to be lower on the basis of a lower notional gearing assumption. Ofgem has set out in the DD that they believe the risks faced by ET and Gas companies are broadly similar. Investors expect the CoE to be commiserate with the risks in the industry and act as an incentive to mobilise capital. Currently investors are receiving a perverse and anti-investability message on potential investment in the electricity transmission sector. They would be required to fund a greater share of ET companies operations, at a much greater, and do so for a lower

[116] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*
[117] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*. Sections 4.1-4.7
[118] https://www.spenergynetworks.co.uk/userfiles/file/Oxera-RIIO-3-Risks-and-Investability-Topics.pdf. p22

allowed return than our 60% geared counterparts. Additionally, this approach is not consistent with RIIO-T2 precedent, which may send signals to investors of inconsistency in regulation of returns. In short, investor perceptions of ET allowed returns will be critical, removing the flat WACC drives a negative perception of ET allowed returns, Ofgem should therefore maintain the flat WACC approach.

FQ 16 Do you agree that our proposed package for gas and electricity companies is investable?
In short, no, we do not believe the proposed package asset out in DD is investable, we do however believe there are legitimate pathways to an investable package. The primary focus of our Chapter 1 response above is in relation to this question and should be read alongside the below as part our position. We summarise our position on the investability of the proposed DD package below.

We welcome Ofgem's continued positive intent on investability, and we recognise the changes from the SSMD as positive steps in the right direction. However, these changes do not go far enough, the proposed package is not yet investable and cannot be confident that companies will have efficient access to sources of financing to help fund the transition to a clean power system.

Investors require earnings which both keep pace with asset growth and achieve nominal returns of 9-10% for high performing networks. Based on our analysis the DD package falls short of achieving this because:

1. The baseline return is too low;
2. There is downside risk across the framework that lowers expected returns further including the position on totex and reopeners; and
3. The incentive framework is incomplete and insufficient to bridge the gap to 9-10% nominal return.

Each of these points is set out in further detail in Chapter 1 - Ensuring an investable finance package above.

We do not believe that Ofgem has thoroughly engaged with the investability arguments that we set out via our Business Plan and in our "RIIO-3 risks and investability topics" paper that was set out from Oxera on behalf of the ENA through the framework. These arguments include Ofgem's move away from flat WACC, and the lack of consideration for wider CoE cross-checks, as were set out in our Business Plan.

Despite Ofgem suggesting in its DD Overview document (para 9.14):

"We have rigorously benchmarked our proposed equity return to ensure that is competitive and efficient. We have also carefully considered stakeholder feedback on how we can broaden our investability assessment"

It is unclear to us how Ofgem has used any of this stakeholder and TO feedback to actually broaden its own framework. Ofgem should disclose how it has assessed TO feedback and what impact, if any, that has had on its position.

We remain fully committed to playing our part to deliver net zero. The benefits of the RIIO-T3 investment of nearly £80bn are clear in terms of the overall consumer benefits case, the enduring impact on economic growth, and the society wide benefits of achieving net zero. The OBR reaffirmed in their July 2025 report[119] that the cost to achieve net zero is significantly lower than the cost of in-action.

Maintaining investor confidence at this crucial juncture is critical. Our DD response sets out the achievable pathway to achieve investability, including a CoE in excess of 6% on a 55% gearing basis, reversal of proposed disallowances which are not supported by evidence, and development of a clear incentive framework allowing strong performing networks to achieve 9-10% nominal returns.

FQ 17 Do you agree with our working assumption that there is risk symmetry within the aggregate balance of the whole price control?
A fair bet for investors, and a clear set of incentives that can drive additional returns for high performing networks is crucial to both financeability and investability of the overall package. We welcome the fact that Ofgem has engaged with this question, but whether or not the outcomes related to our risks result in

[119] https://www.carbonbrief.org/obr-net-zero-is-much-cheaper-than-thought-for-uk-and-unchecked-global-warming-far-more-costly/

a symmetrical risk or a “fair bet” is more of an assessment of the performance against penalties and risks, rather than merely the max rewards and penalties associated with a particular ODI.

Ofgem has, in setting out an illustrative RoRE range in the DD, suggested that there is over 200 bps of outperformance from incentives. However, the incentives package set out is incomplete, and without clear targets or understanding of how Ofgem will set them, represents a downside risk. This makes it difficult for investors to assign any value to the incentive framework. We fully outline our position on each ODI in Chapter 5 - Incentives.

We have set out clear asks to Ofgem that by FD there is a risk symmetry across the full ODI package [see Chapter 5 - Incentives]. However it is important that risk is also balanced across other aspects of the price control such as having the people to support delivery of Clean Power 2030 (CP2030) through Closely Associated Indirects (CAIs), Business Support Costs (BSCs), as outlined in Chapter 2 of this response, automatic and increased pre-construction funding for projects to accelerate investment in low cost and low risk activities which could risk delays later in the process, as outlined in chapter 6]. We also note Ofgem expects TOs to purchase land at risk with no route to funding until cost assessment, we disagree with Ofgem’s policy position and have proposed this is accessed via a use it or lose it funding mechanisms with reporting requirements to Ofgem with consumer protections to clawback inefficient funds as set out in ETQ 26.

On core ODIs (i.e. not including ASTI or TIM), we note that there is a positive skew of rewards and penalties, as we suggest in section 5.1.9. However, this neither considers our “expected position” nor ASTI and TIM, which we would also expect to have more penalties associated with it in practice, than rewards.

Assuming a number of factors, and taking a different view from our Business Plan on ASTI penalties (taking a notional 1/5 of assumed ASTI penalties and rewards to proxy a given year’s RoRE impact rather than the expected amount as a proportion of RoRE) we get a roughly symmetrical RoRE of -1.94% to +1.90%, with the removal of some bias from the SSMD incentive structure, and the tiered TIM approach. However, where we factor in a lower reward than penalty on TIM (for example, assuming a 5% underspend against a 10% overspend given the expectation that overspends are far more likely), this symmetry is removed and the RoRE position is -1.94% to 1.74% (see *section 1.10.4* 1.10.3). We also provide an expected position of our ODIs (ASTI and TIM inclusive) in section 1.10.5, which gets to a negative overall skew of around 7bp.

We have not added in reference to the CSNP-F ODI, as we do not have certainty around what projects would be subject to it. Additionally, Ofgem has proposed that non CSNP projects may be included on a case-by-case basis and therefore, on balance proposing an expected CSNP-F ODI impact would not be feasible. We’ve set our response in Chapter 5, ETQ1-4.

Given the asymmetry in the ODIs presented, the expected return is lower than that of the CoE on average, which is not in line with the ‘fair bet’ principle. Assessing our expectations (see section 1.10.7 of the performance of each of the ODIs (including ASTI and TIM) we estimate an expected return (CoE and adjustments for expected penalties and rewards) as 5.56% (see section 1.10.51.10.6). This also shows an asymmetry of expected returns and therefore biases downwards expected returns and so is not consistent with the fair bet principle. To move towards a more symmetric ODI package of more weighted toward reward given the likelihood of overspend and little to no reward on TIM – we’ve set out key asks for RIIO-T3 FDs in Chapter 5 - Incentives of this response.

We cannot see a credible path for high-performing networks who generate additional value for consumers to achieve the upside on base returns in RIIO-T3 that would make the framework investable, based on DD. We recognise that designing incentives is not a straightforward exercise. We are committed to continuing to assist Ofgem with the task. It is important that ahead of the FD we reach the level of design detail necessary to see that new incentives for RIIO-T3 are ’fair-bet’ and have sufficient strength to make the overall framework investable.

FQ 18 Do you agree with our approach to assessing financeability?
In their Sector Specific Methodology Decision (SSMD), Ofgem has stated that their intention is to move forward with the proposal to integrate long-form financial modelling into their overall financeability

assessment process (para 5.9, Finance Annex) [120]. This enhancement allows for a more detailed and dynamic evaluation of a licensee's financeability over the course of the price control period. Alongside this, Ofgem has chosen to maintain their established approach of conducting an "in-the-round" assessment (para 5.11, Finance Annex) [120] [120]. Alongside this, Ofgem has chosen to maintain their established approach of conducting an "in-the-round" assessment (para 5.11, Finance Annex) [120] [120]. This method involves evaluating the financeability of each licensee not in isolation, but as part of a comprehensive review of the entire regulatory package. The goal of this approach is to ensure that, under these assumptions, licensees would be capable of maintaining financial metrics consistent with a solid investment-grade credit rating.

We welcome Ofgem's recognition of the importance of ensuring that regulated companies remain financeable under the proposed framework. We acknowledge that the rationale underpinning Ofgem's financeability assessment for RIIO-T3 is sound and appreciate the levers introduced to support investment-grade credit quality. However, we must emphasise the need for ongoing scrutiny and refinement of the financeability assessment methodology as we progress into future price control periods. While the current package may be deemed financeable for RIIO-T3, it lacks the durability required to ensure long-term financeability.

Ofgem's proposal to retain a 45-year asset life for RIIO-T3 is understood by us, as it reflects a more realistic alignment with the economic life of assets. Nonetheless, the depreciation policy beyond RIIO-T3 warrants further review to ensure it is both enduring and equitable. A key concern remains the principle of intergenerational fairness—specifically, the risk of disproportionately shifting costs onto future consumers. As discussed in *section 1.8.6*, the existing depreciation gap, estimated at approximately £0.3bn (23/24 prices), remains unresolved and must be addressed in subsequent regulatory reviews to avoid undermining long-term financeability. Were the depreciation gap to be unaddressed, the gap from T5 onwards would increase to £3bn (23/24 prices) [48].

Like RIIO-T2, Ofgem's retention of the Moody's scorecard methodology, which incorporates weighted sub-factors to derive an overall credit rating of 'Baa1', provides a structured basis for assessing financial health. The proposed capitalisation rates—41% for bucket one and 85% for bucket two—result in a higher allocation to the fast pot for us, versus Ofgem's view of the 'natural' rate. While this adjustment is understood to be net present value (NPV) neutral and serves to accelerate revenue recognition, it has notable implications for key financial metrics such as FFO/Net Debt. The influx of operating revenue in RIIO-T3 improves short-term financeability, and under Ofgem's DD modelling assumptions, similar benefits are projected for RIIO-T4[48]. Assuming the capitalisation rates are maintained on an enduring basis, the influx of operating revenue in RIIO-T3 improves short-term financeability, and under Ofgem's DD modelling assumptions, similar benefits are projected for RIIO-T4[48].

However, this front-loading of revenue through the capitalisation rate 2 adjustment introduces significant challenges in the longer term. Specifically, it leads to reduced depreciation allowances in T5 and beyond. This shift adversely affects financeability in future periods, creating a structural imbalance that must be addressed to ensure enduring financial sustainability.

When applying S&P's anchor methodology to Ofgem's Draft Determination, we would be positioned at a 'BBB+' rating, which is considered intermediate. This reflects S&P's classification of regulated utilities as low-volatility entities with strong business risk profiles. Most core and supplementary ratios fall within the intermediate range, indicating broad consistency with Moody's assessment. However, it is important to note that our S&P core ratios fail to meet the 'BBB+' threshold in T5 and T6, primarily due to the substantial front-loading of depreciation and fast money. These ratios remain weak until the mid-2050s, and cash metrics are expected to deteriorate from T6 onwards. This stands in stark contrast to the achievement of required cashflows in RIIO-T3 and RIIO-T4 via the capitalisation rate 2 adjustment, despite the anticipated high levels of investment required to meet net zero targets through 2045. S&P's supplementary ratios also have a similar impact, where FFO/ cash interest and EBITDA/Interest deteriorate from T5 onwards [48].

We acknowledge Ofgem's recognition that credit rating agencies employ differing methodologies. Nonetheless, we remain concerned about the level of assurance provided by Ofgem's current approach. The methodology lacks transparency and certainty, particularly regarding how agencies will treat revenue

[120] *Ofgem. (2025).* RIIO-3 DD - Finance Annex*. Section 5*

and cash flow advancement mechanisms. Without direct engagement and confirmation from these agencies, there is a material risk that such measures may be discounted or reversed in their assessments, thereby undermining the intended impact on credit metrics and the effectiveness of Ofgem's policy.

The concept of a 'fair bet' for investors is partially upheld under current assumptions, such as those derived from *FQ17*, which use a notional one-fifth of assumed ASTI penalties and rewards to proxy a given year's Return on Regulated Equity (RoRE) impact. However, when factoring in asymmetric outcomes—such as a 5% underspend versus a 10% overspend under the TIM mechanism—the symmetry is lost, resulting in a RoRE range of -1.94% to +1.74%. If potential penalties consistently outweigh rewards, investor confidence may be eroded, and the principle of a fair bet compromised. Fundamentally, expected returns should, on average, align with the allowed return to maintain regulatory credibility and attract investment.

We consider Ofgem's financeability approach sufficient for RIIO-T3, we believe further measures or established rules, or approach are necessary to enhance long-term investability and investor confidence. This could include setting a clear and consistent Baa1/BBB+ in all circumstances or signalling to investors and lenders that Ofgem will adopt a transparent approach and stepped methodology to use available cash levers to achieve credit financeability. Regulatory discretion can be preserved to allow for adaptive responses to evolving market conditions, which in turn supports investor confidence. Refer to *section 1.5.5,* where we measure and assess Ofgem's DD financeability package.

We view Ofgem's evolving approach to financeability as a positive development, particularly in light of the language used in the Draft Determination, which acknowledges the increasing scale of investment, financing needs, and the importance of financial resilience. Despite the current rating of 'Baa1', the practical implications of the financeability assessment must be carefully monitored as we enter RIIO-T3. We would welcome confirmation from Ofgem as to the level of engagement with credit rating agencies regarding the effectiveness of the proposed measures in achieving the intended credit outcomes.

In conclusion, while the capitalisation rate adjustment proposed for RIIO-T3 is required to ensure the cashflows needed to secure credit financeability in RIIO-T3, it does not fully resolve the issue of depreciation under-recovery. Instead, it defers the problem to future price controls and exacerbates long-term financeability challenges by concentrating fast money and depreciation in RIIO-T3 and RIIO-T4 at the expense of later periods. An enduring solution must be developed in future reviews to address the remaining depreciation gap and ensure sustainable financeability across the full regulatory horizon

FQ 19 Do you agree with our proposal to adjust bucket 2 capitalisation rates from natural rates to 85% for all ET licensees to support financeability? Are there alternative measures that stakeholders consider more appropriate?
We agree that Ofgem's proposal to adjust the capitalisation rate for RIIO-T3 will drive required cashflows to support credit financeability.

However, we consider this approach as a short-term solution to cashflow and financeability issues in RIIO-3. Whilst this is of paramount importance due to the criticality of the RIIO-3 price control to customer and societal outcomes, we have concerns around the predictability of adjusting the capitalisation rate as a long run solution. Considering the ET's RAV growth, we Ofgem should explore a more sustainable and predictable approach to enhance ET's financeability alongside reasonable capitalisations rates, such as considering asset lives adjustment and depreciation policy.

FQ 20 Do stakeholders have views or evidence on long-term financeability considerations, including the appropriateness of the proposed asset lives?
A 45-year asset life has been proposed by Ofgem which has been welcomed by us for RIIO-T3. However, the depreciation policy for beyond RIIO-T3 will need to be reviewed and be more enduring because intergenerational fairness, where there is a risk transferring costs to future customers, is still a critical point.

Ofgem has stated that they believe the 45-year asset life does not lead to a financeability issue for RIIO-T3 [121] however we believe the result of previous depreciation policy decisions create a perverse effect of

[121] *Ofgem. (2025).* RIIO-3 DD - Finance Annex*. para 8.57*

creating a material "depreciation holiday gap" for existing customers. As discussed in *FQ17*, this gap could £3bn (2023/24 prices) if unaddressed and arises due to the transition between two different asset life assumptions used in calculating regulatory depreciation allowances. Specifically, when [122]:

- Assets added to the RAV before RIIO are depreciated over a 20-year lifespan, meaning their depreciation charges are now largely falling out of the allowed revenue stream.
- In contrast, assets added during the RIIO period are subject to a much longer 45-year depreciation schedule, and the associated depreciation charges are still gradually ramping up.

This is in essence creates a temporary shortfall in allowed depreciation, as the older assets are no longer contribute to revenue, while the newer assets have not yet built-up sufficient depreciation charges to, which could have an adverse impact for us in the long term.

If this depreciation policy remains unchanged it could lead to several significant challenges [123]:

- Intergeneration fairness concerns: Future customers may bear a disproportionate share of costs for assets that are already in use today. Using Green Book methodology, we estimate a real cost to our customers of £0.3-0.4bn from the deferral of depreciation under RIIO policy [124].
- Financeability issues: We may struggle to maintain adequate cash flows and credit metrics, potentially affecting our ability to raise capital, especially in the long term. This coupled with the front loading of cash measures via the capitalisation rate discussed in *FQ18*, leads to long term financeability issues.
- Long-term affordability risks: Delaying cost recovery could result in higher in future periods, undermining the key principles of affordability and stability.

Refer to Annex 2.12 for further analysis.

FQ 21 Do you agree with our proposal to implement the Financial Resilience measures as laid out in our SSMD and the proposed methodologies set out above?
We continue to be of the view that additional financial resilience measures are not required. We understand and fully support the requirement to ensure public interest entities of critical national importance to have financial resilience standards. However, electricity transmission companies have not had issues with financial resilience since privatisation. We therefore see additional resilience measures as unnecessary and simply creating additional regulatory burden without any associated benefit. We believe this is an inappropriate mirroring of rules introduced in other sectors (e.g., water and energy retail) which have had demonstrable, significant financial resilience issues in recent times, on the contrary, energy networks companies have remained financially resilient despite the volatile external conditions.

As part of our Sector Specific Methodology Consultation (SSMC) and SSMD response we set out a number of potential issues and circumstances where Ofgem's financial resilience proposals may not be appropriate. These issues have not been directly addressed or considered. More guidance is required for how these measures will work in practise.

FQ 22 Do you agree with the proposed position that by including robust protections within the Price Control Financial Handbook, a tax forecasting penalty is not required?
Yes, we agree that a tax forecasting penalty is not required and would not be in consumers' best interests.

[122] Annex 2.12. NERA. (2025). *Depreciation under-recovery from RIIO-1 extension of asset lives, page 7*
[123] Annex 2.12. NERA. (2025). *Depreciation under-recovery from RIIO-1 extension of asset lives, page 23*
[124] Annex 2.12. NERA. (2025). *Depreciation under-recovery from RIIO-1 extension of asset lives, page 21*

FQ 23 Do you agree definitions for ANDt and TDNIt should be updated to reflect the principles outlined in paragraph 7.41?
Yes, we agree with Ofgem on the revised definition of ANDt and TDNIt to align with the accounting standards and tax legislation. Considering that fair value adjustments, financial instruments covered under IFRS 16/FRS 102 and IFRS 17 would be treated in line with the principle of economic substance over legal form, would reflect the direct impact of the hybrid instruments on companies' liabilities. We also assume the new definition would enhance transparency across licensees' overtime especially as financial structures evolve. However, the benefits are not without trade-offs, such that companies may experience higher clawbacks due to the broader definition of scope. The complexity in implementation might require adjustment to the models and more effort because of the broader scope and recognition requirements of the instruments involved. Hence, we would propose that Ofgem provide a clear guidance and transitional arrangements for stakeholders to assess the retrospective and prospective impact on all stakeholders.

FQ 26 Do you agree with our proposal to maintain the existing depreciation policy for electricity transmission assets?
Ofgem has proposed a 45-year asset life which has been welcomed by us for RIIO-T3. However, the depreciation policy for beyond RIIO-T3 will need to be reviewed and be more enduring because intergenerational fairness, where there is a risk transferring costs to future customers, is still a critical point. Refer to *FQ20* for further detail on SPEN's view of the depreciation policy for ET assets.

FQ 27 Do you agree with our proposals for the RAM thresholds and adjustment rates?
We are broadly comfortable with the continuation of RIIO-2 RAM thresholds and adjustment rates.

FQ 28 Do you agree with our proposal to include programmes such as ASTI within RAMs?
We are broadly comfortable with the inclusion of ASTI programmes within RAMs.

FQ 29 Do you agree with our proposals for RAV Indexation?
We welcome the move to a more financeable regulatory framework than was the case in SSMD, and the move to a lower ILD, in isolation, means that a greater proportion of our WACC will be subject to nominal indexation. We have found that the changes in the ILD are reasonable given the ILD of the sector.

We note however, that partial RAV indexation is a material departure from existing GB regulatory precedent and it is yet unknown the implications of this approach on an enduring basis – a wider impact assessment should be conducted for the long-run.

FQ 30 Is there any additional evidence we should consider to improve our setting of regulatory capitalisation rates?
Ofgem should ensure that there is consideration of a more sustainable approach, that would enhance consistent policy beyond RIIO-T3.

Ofgem also need to assess the impact of changes in the UMs due to switch from SSMD natural capitalisation to the DD proposed approach. From every indication, the changes in capitalisation rates would directly impact the UMs and this further increase the forecasting risk for the ET companies and customers.
Refer to FQ18 the impact of SPEN's view of capitalisation rates being used as a lever, having a downside impact on financeability issues in future price controls.

FQ 31 Do you agree with the approach to maintain the RIIO-2 treatment for disposal of assets?
We are comfortable with Ofgem's proposal to maintain the RIIO-2 treatment for disposal of assets

FQ 32 Do you agree with the proposal for the ex ante base revenue definition we will use to calculate the re-opener materiality thresholds?
We support Ofgem's proposal to retain the ex-ante base revenue definition to calculate the re-opener materiality threshold for Special Condition 3.3 Resilience Re-opener, however have fundamental concern with the same application to Special Condition 3.10 Non-Load Re-opener which we outline further in ETQ 61.

FQ 34 Do you agree with the proposal to move to using nominal WACC as the single uniform TVOM?
We maintain the view that separate TVOM approaches are necessary, using SONIA/bank rate for differences in collected revenues, and nominal WACC for true ups for allowed revenues. Whilst we understand the attractiveness of a single true up and single TVOM, we believe that given the different types of true-ups, different TVOM is necessary. Further, we believe a split of collected revenue true up and allowed revenue true up is helpful in understanding the scale and drivers for the different types of true-up's. Additionally, the functionality to split these true-ups exists within the models due to the forecasting penalty functionality.

Should Ofgem decide to go ahead with a single true-up and TVOM, despite the principles differences requiring separate treatment, we agree the nominal WACC would be the best solution.

FQ 35 Do you agree with the proposed base revenue forecasting penalty mechanism?
No, the introduction of a base revenue forecasting penalty would be inappropriate for RIIO-T3.

In RIIO-T2 Ofgem correctly abandoned the introduction of a base revenue forecasting penalty for TOs. This was due in part because of the nature of electricity transmission projects being larger and therefore more susceptible to timing scope and cost changes, further the scale of uncertainty mechanism totex was unprecedented in RIIO-T2 at the time. Uncertainty mechanism expenditure accounted for forecast 6% of totex during the first tariff setting of RIIO-T2, this has risen to 52% of totex in the latest forecast. Uncertainty mechanism expenditure is inherently more volatile and unknown. In RIIO-T3, the proportion of our totex that relates to uncertainty mechanisms is 86%. Additionally, there are industry reforms outside the control of the TO which make forecasting these uncertainty mechanisms difficult e.g. connections reform and CSNP. Revenues in RIIO-3 are therefore potentially much more volatile, even expanding the thresholds to 8% of base revenue for us is insufficient – just an 18% movement in fast money and pass-through costs would trigger an automatic financial penalty.

We strongly believe that it would be incorrect and inefficient regulation to automatically apply penalties to TOs leaving it to the TOs to then have to prove variances were out with their control. This 'guilty until proven innocent' approach goes against Ofgem's regulatory approach in other areas. Instead, at most, Ofgem should scrutinise variances over a certain threshold when they occur, and should those variances be shown to be driven by a TO error, or an unreasonable forecast then a penalty could be applied.

Further we posit that there is already a strong incentive to forecast accurately. Analysis of variances in RIIO-T2, similar to that which Ofgem has undertaken, shows a clear aim of accurate forecasts without the need for a financial penalty attached. Ofgem has stated in licence drafting working group calls that the lack of would-be threshold breaches in previous years supports their approach, we strongly disagree. The lack of previous breaches shows that:

1. There is already a sufficient incentive to accurately forecast, without need for a financial penalty attached. It is in our interest to ensure the revenues we receive each year are closely aligned to the costs we incur and outputs we deliver, uncertainty and volatility is not only bad for customers but also bad for cashflows and bad for shareholders.
2. The level of uncertainty mechanism expenditure compared to that forecast for RIIO-T3 is likely to be the driver of variances. Ofgem should undertake analysis across the sector to understand how volatility in actual data moves as there is a greater share of uncertainty mechanism expenditure

Further the functionality within the financial model suggests this can be retroactively applied, meaning if historical allowances are restated a breach could be achieved with an automatic penalty attached. The scope for Ofgem to scrutinise companies' forecasts, both in the first instance during RRP/AIP reporting to assess the reasonableness of year ahead forecasts, but also an ability for Ofgem to scrutinise large variances between live allowed revenue and priced revenue is more than enough of an incentive for networks to continue to accurately forecast. We do not understand the need for the introduction of this penalty mechanism and what the aim is that this mechanism would achieve that is not already the case.

FQ 36 Do you agree that the thresholds have been set appropriately?
No, as we do not agree with the appropriateness of forecasting penalty for RIIO-T3. Base revenues are significantly more volatile in RIIO-T3, and an increase to 8% threshold is insufficient.

ETQ 64 Do you agree with our approach on insurance? What methodological improvements can we make?
It is positive that Ofgem recognises the need to separately assess insurance costs and that the primary reason for the cost increase in RIIO-T3 relates to undersea cables. Whilst Ofgem acknowledges separate assessment of undersea cables may be appropriate it was discarded in DD as it did not fit with the chosen methodology.

Benchmarking against onshore network length (a combination of OHL (vast majority) and underground cable (UGC) (minority)) may not be appropriate as length is not a key cost driver. The key factors are the risk and cost associated with the installation and operation of the subsea cables and potential repairs.
The cost of insuring undersea cables must be reconsidered and treated as a special case due to the hostile environment in which they are located. For example, vessels are required for installation, which are limited in supply which therefore drive-up costs. The number of suppliers capable of undertaking such installation work is also a factor – there are far fewer contractors able to go offshore and install cables, than can do this onshore. There can be major variations between subsea cable projects, if for example one subsea cable is in deeper water than another (requiring larger vessels) or has different seabed conditions along the cable route than another cable. Weather is also a factor – repairs expected to take 10 days could take double that if there is no suitable weather window, and the TO will be paying standby costs in the meantime. The costs of such insurance are competitively tendered as evidenced in our Business Plan submission.
We went to market early this year to get a quote to add Western Link into the offshore policy for operations. The quote we obtained was a cost of [redacted]. This compared with a cost of insuring the entire SPEN (SPT+SPD+SPM) network of [redacted] per annum with a per claim deductible of only [redacted].

This is strong evidence that the market is not valuing this on a network length basis, and based on the above, Ofgem should undertake a separate qualitative approach to assessing subsea insurance costs

ETQ 65 Do you agree with our approach to pension scheme admin and PPF levy? What else should be considered within this approach?
Yes, we agree with Ofgem's proposed approach.

Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)

2.1 Overview

2.1.1 At a strategic level, it is clear that Ofgem considers growth to be essential. From the start of RIIO-T3 Ofgem has referenced the need for "unprecedented network expansion in electricity transmission" as critical to support the Government's growth plans as well as being in the interest of consumers. Ofgem's CEO has recognised that there are only five years to deliver the government's Clean Power 2030 (CP2030) and the margin for error is minimal.[125] We have consistently welcomed this position and indeed continue to support this view given the scale of growth needed for the Scottish TOs and the fundamental structural review we have carried out for our organisation to enable this growth. To put this growth in context, in our Business Plan we highlighted the need for our staff to grow by 1,422 (+151%) by 2028/29. We discuss our growth plans in more detail in Chapter 6 - Growth Mechanisms.

2.1.2 While we consider that many aspects of Ofgem's DD are supportive of growth objectives, we are concerned that if Ofgem's proposed approach to the assessment of our indirect costs remains unchanged, this risks undermining Ofgem's growth duty and objectives, particularly with regards to its important role in the government's mission to 'kickstart economic growth'.[126] This has consequential implications for GB consumers by delaying efficient investment and increases the risk of higher future costs. Our indirects activities are not just a consequence of our investment but an enabler, critical to delivery, and must be in place at the right time to drive that delivery. For the Scottish TOs, the scale of growth required has a direct impact on the associated scale of indirects which will be greater than that faced in previous price control periods. For context, our business plan identified total transmission investment in RIIO-T3 of £10.6bn (over three times more than RIIO-T2) with a staff increase of +151%, SHETL also envisages a staff increase of around c. 230%, whereas for National Grid the equivalent staff increase is c. +50% over the same period.

2.1.3 Closely Associated Indirects (CAIs) include the costs of key activities which are critical to and which complement our project delivery for our investment programme, such as network design and project management. Business Support Costs (BSCs) include wider organisational and operation support functions such as HR, legal, commercial, stakeholder, IT, facilities management and regulation to support the growth in the scale of the organisation. We provide two case studies in Annex 3.3 which provide a more detailed breakdown of the relevant functions.

2.1.4 It is crucial to a successful RIIO-T3 outcome that there is timely availability of both CAIs and BSCs which includes the required staff who perform the critical roles which will drive the development and delivery of our investment programme needed for CP2030 and to meet the Government's 2050 Net Zero targets. It is notable that the ramping up of these resources has already begun during RIIO-T2, and our year-on-year workforce growth trajectory from 2024/25 to 2030/31 is demonstrated in our Workforce Modelling and Growth sections in our Business Plan. This proactive scaling is essential to ensure that staff are recruited, adequately trained, provided with the required office facilities and essential IT equipment, and consequently prepared to develop well-justified, efficient, and cost-effective investment proposals, engage effectively with stakeholders and regulatory bodies, and deliver the complex infrastructure required for a net zero-aligned energy system. It is critical that this happens in a timely way, when those new resources are required.

2.1.5 Delivering this requires a package of measures that enable sufficient funding which in turn enables us to size the business in order to satisfy the Government's Net Zero and CP2030 targets. We strongly believe that adopting an approach based on Best View forecast in line with Ofgem's

[125] https://www.ofgem.gov.uk/publications/jonathan-brearley-speech-future-utilities-conference Jonathan Brearley, Jan 2025 – "*Under the vision that Ed Miliband has set out to get to 2030, the principle benefit we see is that we will get to a more stable energy system for customers, and avoid the sorts of price spikes that we've seen in the past*"
[126] Ofgem (2025), 'Forward Work Programme 2025/26', 1.10.

Business Plan Guidance is the optimal way to do this. We also see a role for adjustment mechanisms to enable funding where required but which also protect consumers by returning funding where not required. Taken together, it is important to put in place a balanced approach to achieve these objectives.

The impact of Ofgem's draft determinations on indirect cost allowance

2.1.6 In Ofgem's DD, CAIs and BSCs are separately assessed via a combination of econometric benchmarking, and a more forward-looking assessment, with each assessment being assigned a weight of 50%. The following summarises the specific methods of assessment for each cost category:

CAI Assessment

2.1.7 **Historical regression -** A Pooled Ordinary Least Squares (POLS) multivariate regression based on the historical period (2013/14–2023/24). CAI is regressed against the following drivers: (i) Modern Equivalent Asset Value (MEAV), (ii) CAPEX, and (iii) a time trend.

2.1.8 **Forward-looking analysis -** A TO-specific ratio benchmarking, whereby the median CAI to CAPEX and CAI to MEAV ratios across the RIIO-T3 years are applied to baseline CAPEX and MEAV respectively to produce a set of modelled allowances from each driver. An equal weighting is then applied between the two ratio analyses to form a final modelled outcome for the forward-looking assessment.

BSC Assessment

2.1.9 **Historical regression -** A POLS regression based on the historical period (2013/14–2023/24) using a Composite Scale Variable (CSV) as the sole driver of BSC. The CSV is made up of three components (with weights) as follows: (i) MEAV (79.5%), (ii) FTE (11.5%), and (iii) TOTEX (9.0%).

2.1.10 **Forward-looking analysis -** A TO-specific trend analysis whereby the changes in best-view FTE are used as a growth factor, projected from 2026 onwards.

Overall impact of Ofgem's assessment

2.1.11 Overall, when triangulated across the two approaches (and including the separate assessments for certain CAI and BSC costs), we have an efficiency challenge of 32% (£185m) in CAI and 39% (£149m) in BSC baseline allowances. This leaves us materially underfunded to efficiently develop and manage our RIIO-T3 investment programme and thus compromises our ability to enable the levels of growth required during the RIIO-T3 period.

Table 2-1 - Difference between SPT assessed and Ofgem proposed indirect cost allowances 2023/24 prices [127]

Cost Area	SPT Submitted Adjusted (£m)	Ofgem Proposed (£m)	Difference (£m)	Difference (%)
BSCs	385	236	-149	-39
CAIs	580	396	-185	-32

[127] Extract from Ofgem's Draft Determinations 'RIIO-3 Draft Determination – SP Transmission' (Table 10). These reflect Ofgem's modelled cost which represents a subset of SPT's total submitted indirects of £1.52bn.

Summary of our proposals on indirects

2.1.12 In order to reach a reasonable package at FD that will deliver CP2030, we are looking to work constructively with Ofgem to provide any data or other supporting information required to achieve this. To do so we consider that in FD Ofgem should adopt the following proposals:

1. **Revert to using Best-View forecasts (in line with Business Plan Guidance) to better account for growth rather than shifting to a flawed baseline approach** – While the Business Plan Guidance required plans to be submitted on a 'Best View' basis in line with the Scottish and UK Government Climate Change targets and the NESO stipulation for capacity transfers across the UK network, Ofgem has based its analysis on an estimate of baseline costs. Ofgem's decision to adopt this approach was based on the fact that it did not have consistent forecasts of costs from the three TOs [redacted] and potential uncertainties in the associated Indirect requirements. The result of Ofgem's decision to not follow Business Plan Guidance and adopt a baseline approach at DD is to put undue weight on flawed historical analysis that does not account for growth. Further, the resulting costs are based on a cut of information provided at short notice in response to a Supplementary Question to which very little guidance was provided and which, as a result, in highly likely to include inconsistencies. We note that Ofgem recognises the merits of a Best View approach [redacted]. We welcome this as we consider adopting an approach based on Best View is the best way to provide a robust view of the required expenditure for each of the networks.

2. **Ensure parameters, thresholds, and modelling assumptions are evidence based, derived using robust analysis and enable the required CAI and BSC allowances** – Delivering the required investment in RIIO-T3 will depend on securing the necessary internal resources. Ofgem itself acknowledged this in stating "We recognise that delivering CP2030 is likely to require an increase in activity during RIIO-ET3 and that TOs will need to prepare in advance." We agree with this assessment, and for us this amounts to a step-change in growth across RIIO-ET3. This means that CAI and BSC will be critical to success. However, DD proposals currently significantly understate these allowances. All parameters, thresholds and modelling assumptions should therefore be grounded in robust evidence and analysis, ensuring they reflect the true scale of resources required to meet CP2030 demands.

3. **Revise mechanisms for additional funding to support delivery at pace** – We welcome the proposal to provide a further CAI UIOLI allowance of £78m upfront for capex projects falling under uncertainty mechanisms. While positive, this still leaves a significant proportion of our required CAIs unfunded. For example, the £25m project threshold alone could exclude up to 63% of RIIO-T3 projects which would provide an additional c£33m of allowance. We note Ofgem's proposal for a mid-period reopener for BSC. While reopeners can be useful, in this case the timing is too late as investment will be required up-front to enable us to plan, develop and deliver projects to meet Net Zero targets by 2030 and beyond. In addition, the proposed threshold for triggering the reopener is set so high that we would be unable to access it, even if our costs out-turned in line with our Best View Forecast. We therefore recommend a range of pragmatic revisions to these mechanisms to increase their effectiveness and ensure funding is available early enough to support timely delivery.

2.1.13 As part of our response, we are also submitting independent reports by NERA[128] and Economic Insight[129] on the indirect cost assessment. The NERA report highlights the reasons why Ofgem's regression analysis provides an unreliable basis for estimating TO's efficient indirect costs and sets out arguments why the resource needs would not be suitably addressed by the proposed CAI UIOLI and BSC Re-opener mechanisms. The report by Economic Insight provides a critical review of Ofgem's BSC and CAI modelling including the weaknesses of both the regression and forecast models and provides views on alternative approaches. We draw on the findings of both reports at various points in this chapter. In addition, throughout our analysis and in the development of this response we have had ongoing support from S&C Electric and Oxera.

2.1.14 The draft determination did not propose a solution to the increase in national insurance contributions set out in the Autum budget. SPT's RIIO-T3 plan was prepared in advance of this decision, and therefore does not reflect the impact of this increase in employment costs. A regulatory mechanism is required to adjust allowances appropriately to reflect the new National Insurance requirements on TOs. SPT will look to engage with Ofgem on the appropriate route to funding these costs, however it requests that an uncertainty mechanism is developed to address changes in government policy that have cost implications for regulated TOs, given these are outside the TOs' reasonable control and can have a material impact on costs during the price control period.

2.1.15 The remainder of this Chapter is structured as follows:

- Section 2.2 sets out the common methodological issues with Ofgem's assessment of CAIs and BSCs
- Section 2.3 sets out expenditure specific issues for CAIs
- Section 2.4 sets out our proposed alternatives for CAIs
- Section 2.5 sets out our comments on the CAI UIOLI adjustment mechanism
- Section 2.6 sets out expenditure issues for BSC
- Section 2.7 sets out our proposed alternatives for BSC
- Section 2.8 sets out or feedback on separately assessed BSC
- Section 2.9 sets out our comments on the proposed BSC reopener mechanism and our asks for Ofgem to ensure that the reopener works for growth in RIIO-T3

[128] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August.
[129] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August.

2.2 Common Methodological Issues

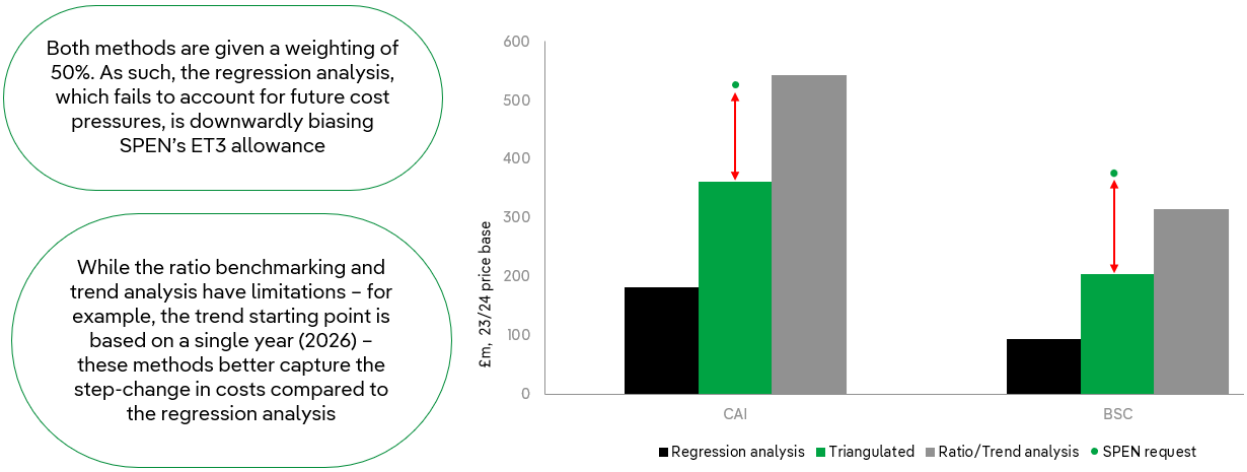
Inconsistent outcomes

2.2.1 It is good practice to use multiple methods to assess allowances. However, to ensure that those models are robust, it is imperative that they are properly designed and calibrated to the forward-looking costs that they are purporting to measure. At DD, Ofgem has used two methods to assess indirect expenditure:

- econometric modelling of historical data and an extrapolation thereof; and
- ratio benchmarking or trend analysis of forecast data.

2.2.2 If both methods are genuinely robust, they should produce broadly consistent outcomes, thereby increasing confidence in Ofgem's assessment. The following figure and table show the discrepancy between Ofgem's econometric assessment relative to the forward-looking assessment. They highlight that the outcomes under the two methods are, in fact, materially different. In the case of BSC, the difference between the forward-looking trend analysis and the regression analysis is £154m (166% of the regression modelled costs) and in the case of CAIs the difference is £360m (199% of the regression modelled costs) These constitute material discrepancies which undermine confidence in the modelling.

Figure 2-1 - Discrepancy between allowances from the regression analysis and forward-looking analysis



Source: SPEN (2025), SPT slides on Indirects and MEAV for CAWG 22, 30 July 2025 (Note: typo corrected for the starting point of trend analysis in the lower left text box, i.e. 2026, instead of 2024)

Table 2-2 - Modelled CAI and BSC Costs for SPT under Ofgem's Historical Regression Models and Company Specific Analysis, 2023/24 prices

		Weight	2027	2028	2029	2030	2031	RIIO-ET3
CAI								
Ratio analysis	£m	50%	131.2	116.3	109.5	100.4	83.1	540.6
Regression model	£m	50%	41.5	38.5	36.3	33.9	30.4	180.6
Difference between two modelled costs	£m (%)		89.7 (216%)	77.8 (202%)	73.2 (202%)	66.5 (196%)	52.7 (173%)	360.0 (199%)
BSC								
Trend analysis	£m	50%	47.7	49.8	50.0	49.7	49.6	246.8
Regression model	£m	50%	18.7	18.6	18.6	18.5	18.4	92.9
Difference between two modelled costs	£m (%)		29.0 (155%)	31.1 (167%)	31.3 (168%)	31.2 (169%)	31.2 (169%)	153.9 (166%)

Source: NERA Analysis of Ofgem DD Benchmarking Files.

2.2.3 The figure and table show that the allowances derived from the econometric benchmarking are roughly three times lower than that from ratio/ trend analysis. This divergence indicates that at least one of the methods lacks sufficient robustness. Moreover, our expenditure request lies within the range suggested by the two methods. That is, if Ofgem considers both methods to be robust, there is no evidence that our proposed expenditure is inefficient.

2.2.4 While Ofgem's ratio benchmarking and trend analysis have limitations, such as using a single year (2026) as the baseline for the trend analysis[130], it better reflects our forward-looking operating circumstances better than the outturn-based regression analysis. For example, a significant element of the step-increase in indirect costs in RIIO-ET3 is driven by rising labour costs, which account for c. 86% of our forecast CAI costs. As such, we consider the forward-looking assessment to be more robust in capturing the step-increase in the growth activity required across RIIO-ET3 to deliver government targets than Ofgem's regression analysis. (For a full discussion on the limitations of Ofgem's econometric benchmarking of CAI and BSC in its DD, please see sections 2.3 and 2.4 below).

<u>Inconsistent and ill-considered modelling principles</u>

2.2.5 Ofgem has neither clearly articulated the modelling principles underpinning its approach nor applied them consistently across its indirect cost models. As a result, the indirect models presented at DD lack robustness and are not fit for purpose.

2.2.6 First, the models are highly sensitive to the time period over which the data is modelled. Specifically, when forecast data is included in the modelling period,[131] all coefficients across the cost drivers in the indirect models either reduce materially in magnitude (which have not been validated) or become statistically insignificant. Furthermore, the model fit reduces materially. A

[130] The analysis assumes that the ratio in the selected year is broadly representative of the ratio that an efficient company would expect in RIIO-T3, which appears to be an untested assumption at the DD. This could be validated using sensitivity analysis (e.g. selecting different years) or by estimating the ratio over a longer time horizon, consistent with how Ofgem estimates the benchmark in its Totex models for DNOs and GDNs.
[131] Ofgem typically includes forecast data in its cost modelling, either directly (such as in its Totex model for gas distribution networks) or indirectly (such as in its more granular assessment of TOs' Capex requirements).

robust model should be largely insensitive to the chosen modelling period, and testing for such sensitivity is a key diagnostic routinely applied by Ofgem, Ofwat, and the CMA in previous determinations. For example, Ofwat assesses its econometric base cost models in water and wastewater using a range of model robustness tests, which includes ensuring the model results are stable and robust to changes in underlying assumptions including different sample periods.[132] If the modelled relationship is unstable, it suggests that the relationship between drivers and costs differs between historical and forecast periods; in other words, that there is a structural break. Ofgem has already acknowledged that structural breaks may be a concern,[133] and formal statistical tests suggest that one is present in the current dataset. In such cases, models cannot accurately predict future expenditure requirements and should not be used to set allowances. Relying on statistically inferior models risks underfunding and undermines the sector's ability to meet the demands of customers, the regulator, and government during RIIO-ET3. Where Ofgem has recognised potential structural breaks in other cost areas (e.g., NOCs, Load and Non-Load Capex) and proposed remedies, the same approach should be adopted here.

2.2.7 Second, Ofgem's choice of cost drivers does not adequately reflect the anticipated step-increases in resources needed to deliver the growth it has itself identified.[134] In particular, Ofgem places significant weight on MEAV in both the BSC and CAI models. MEAV measures the replacement value of operational assets and is relatively stable over time; it reflects past investment, not future investment needs. CAI and BSC costs arise from support functions that operate the asset base, not from the asset value itself. A TO with a high MEAV may have a modest investment programme, and thus low indirect costs, whereas a smaller TO with a major investment programme may have high indirect costs. Disproportionate weighting on MEAV risks systematically underfunding small TOs with large investment programmes. A more appropriate driver would be one that is responsive to step-changes in costs and better correlated with indirect expenditure.

2.2.8 Third, Ofgem's approach to selecting a single 'best' model from a wider suite appears overly reliant on historical model fit, despite several alternatives producing similar fits and outturn-based models failing to capture necessary step-changes. This approach is both wrong and irrational because models of similar statistical quality can yield materially different allowances. For example, in BSC modelling, Ofgem tested six models producing allowances for us ranging from c. £93m (the chosen DD model) to £137m. Selecting the lowest-outcome model, without clear evidence that it is statistically or operationally or economically superior, introduces bias. A more robust approach, consistent with regulatory precedent, would be to consider a range of sensible models and triangulate across them to mitigate bias risk.

2.2.9 These limitations all stem from unclear, inconsistently applied and ill-considered modelling principles. At a minimum, Ofgem should clearly articulate its modelling objectives and selection criteria. Building on established regulatory precedent[135], Ofgem should implement the following

[132] There are a range of example of regulators highlighting the importance of model sensitivity. For Ofwat, the issue is set out in its PR24 document 'Econometric base cost models for PR24' - Econometric_base_cost_models_for_PR24_final.pdf
[133] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.151.
[134] Indeed, this could be one driver of the structural break identified in the paragraph above.
[135] Regulatory precedent on modelling has been established by Ofgem over a number of RIIO price controls. In particular, we would highlight Ofgem's RIIO-2 'Tools for Cost Assessment' document which outlined key principles of Ofgem's model specification and selection. This includes the importance of robustness, transparency, and high-data quality: https://www.ofgem.gov.uk/sites/default/files/docs/2019/06/maindocument_riio-2_tools_for_cost_assessment.pdf. We further note that Ofwat clearly outlines its principles and objectives for its base cost assessment across water and wastewater in order to guide its model selection and criteria. See Ofwat (2023), 'Econometric base cost models for PR24', April, pp.15–16.

core principles in its model development process to ensure the regression analysis is robust and produces outcomes with a high degree of confidence:

- **High data quality**. Data should be assured, and measured consistently across TOs, and be of high quality to ensure model reliability and effective benchmarking.
- **Sound statistical quality**. In general, the models should pass relevant statistical tests and fit the data relatively well. However, it should be acknowledged that the sample is small and heterogenous, and the assumptions behind statistical tests may not necessarily be valid.
- **Strong operational rationale**. Cost drivers should be known to have a causal relationship with costs from an operational perspective. Drivers should explain differences in costs between TOs as well as changes in costs over time (e.g. forward-looking cost pressures).
- **Robustness**. The models should not be overly sensitive to reasonable changes in the data or modelling assumptions, such as the inclusion/exclusion of individual years, time-periods, TOs or minor amendments to the model specification (e.g. changing the weights on CSVs).
- **Consistency in outcomes**. A variety of sensible models should be used to assess costs. The outcomes from different models should produce a consistent picture and, if not, the causes of different outcomes should be investigated.
- **Aligned with incentives**. Models should align with Ofgem's wider objectives and duties as a regulator, including its role in promoting economic growth, promoting efficiency, protecting consumers, ensuring resilience and encouraging innovation.

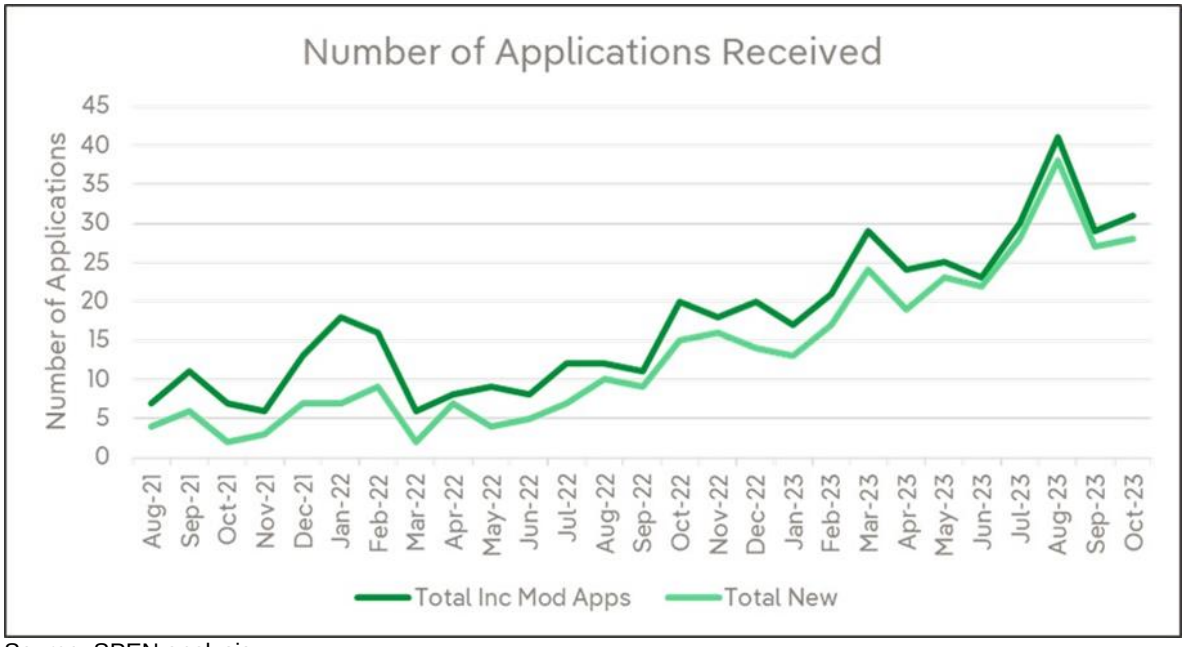
Unjustified weighting

2.2.10 The 50:50 weighting represents an explicit decision by Ofgem to give equal importance to two fundamentally different approaches: a forward-looking method (ratio benchmarking) and a method that assumes the future relationship between costs and operating circumstances will be similar to those observed in the past (regression analysis based on outturn data). As shown in Table 2-2, this assumption does not hold.

2.2.11 This weighting has not been justified and is plainly untenable. Given the large discrepancy in outcomes between the two methods, even minor changes to the weighting have a substantial impact on modelled allowances. For example, increasing the weight on the forward-looking analysis by 5% increases our modelled CAI allowance by approximately £18m (and vice versa). For BSC, the same adjustment increases our allowance by £8m. Although Ofgem argues that the 50:50 split 'balances' the two analyses, the volatility of results from small changes in weighting highlights the inconsistency, and therefore lack of robustness, arising from at least one of the methods.

2.2.12 Moreover, one method can, albeit imperfectly, account for forward-looking cost pressures, whereas the other cannot. In reality, the future operating environment will differ substantially from the historical data used for the regressions, which was characterised by relatively stable activity and slow growth. The figure below illustrates the rapid growth in the number of connection enquiries from April 2021 to October 2023, a trend expected to continue into RIIO-3, driving significant increases in indirect activities.

Figure 2-2 - Growth in connection enquiries



Source: SPEN analysis

2.2.13 Overall, we consider the choice of the 50:50 weighting is wrong and irrational in the circumstances given it insufficiently accounts for the investment requirements of the Scottish TOs which have a significantly greater requirement for growth going into RIIO-T3 when compared with RIIO-T2. Given the evidence showing that future relationships between costs and operating circumstances are different to past relationships, and since minor adjustments to the weights result in a material impact on our baseline allowance for CAI, we consider the econometric benchmarking to not be robust at DD. In particular, it highlights the inability of the historical benchmarking to sufficiently account for the growth anticipated by us to deliver CP2030.

2.2.14 We also note that some of the shortcomings in the CAI and BSC modelling may stem from the late decision to model these costs independently rather than through a combined regression for BSC and (elements of) CAI, which we consider may be a more robust approach that warrants investigation. Notwithstanding that we remain of the view that a combined regression is the most robust and appropriate approach to CAI and BSC modelling, for the purposes of this response only we have sought to take a constructive approach and put forward suggested improvements to Ofgem's approach which are required, at a minimum, to make the allowances for CAI and BSC to be fair and reasonable. While we maintain the most appropriate route would be to revert to Best View, we welcome the opportunity to work with Ofgem on the joint modelling of CAI and BSC before the FD because the present proposal of a 50:50 weighting is not fit for purpose and must be amended if indirect costs are to be properly assessed. This conclusion is supported by the findings of Economic Insight which are presented in Annex 3.2.[136]

2.3 Ofgem's CAI modelling

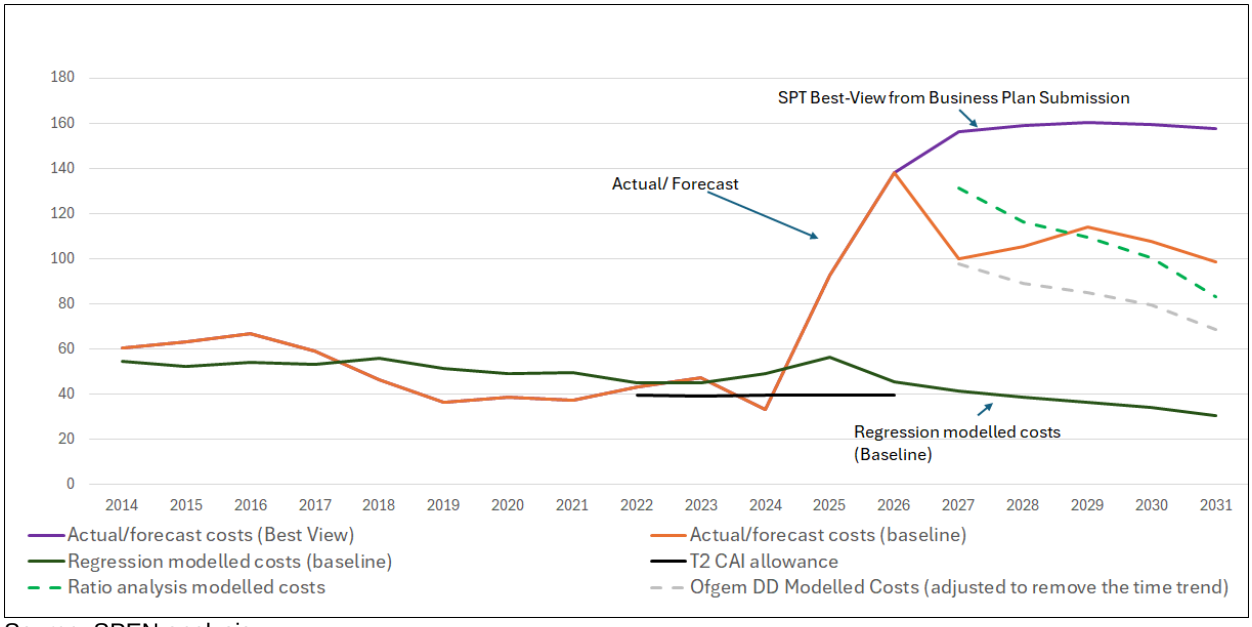
2.3.1 For RIIO-ET3, we are forecasting a step-increase of up to c.316% in yearly total CAI costs relative to the outturn yearly costs of RIIO-ET2. As acknowledged by Ofgem, our step-increase in indirect costs reflects the current size of the company, and the different levels of growth required relative to other TOs to deliver our anticipated Capex programme.[137] Therefore, it is vital that Ofgem's CAI assessment is able to account for the differing levels of growth expected in RIIO-ET3, to

[136] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August, Sections 2G and 3G, p. 25 and 37.
[137] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.144, 5.90.

ensure TOs are funded sufficiently, and that such costs associated with growth are indeed efficient.

2.3.2 The historical regression of CAIs uses MEAV and Capex as cost drivers, includes a statistically insignificant time trend, and is based on the outturn period 2013-14 to 2023-24. The figure below compares our actual and forecast baseline (and Best View) CAI costs against the modelled costs from Ofgem's DD CAI regression model and its ratio analysis.

Figure 2-3 - CAI actuals and forecast costs against modelled costs



Source: SPEN analysis.

2.3.3 While the regression model broadly aligns with our costs on an outturn basis (2014–2024), it fails to capture the step-increase in activity required for RIIO-ET3. This is evident from the material divergence shown in the figure above between our forecast costs (the orange line) and the regression model's predicted costs over RIIO-T3 (the solid green line) and relative to our modelled Best-View (the purple line). Despite Ofgem acknowledging that this step-change is necessary to support our anticipated Capex programme, its CAI models unintuitively project a decline in costs during RIIO-ET3, to a level below both our RIIO-ET2 allowances and our RIIO-T2 actuals/forecasts. This outcome demonstrates that the regression analysis, as applied, is not fit for purpose, which is further elaborated in the following sections.

Time Trend

2.3.4 Ofgem includes a statistically insignificant time trend, that is materially far from reasonable statistical significance thresholds (p-value of 0.28, meaning there is a 28% chance of observing a coefficient as high if there is no true time trend). This is a contradiction to its own modelling principle since Ofgem states that "models containing statistically insignificant parameters [are] typically excluded from further consideration."[138] Further, Ofgem also directly recognises that forward-looking pressures, such as increasing FTEs or operational expansion "are not visible in historical data".[139] We consider that statistically insignificant cost drivers can be included in the cost models, only if: (i) there is a strong operational rationale for including such drivers; and (ii) the magnitude of the coefficient is broadly aligned with operational expectations. At PR24, Ofwat rejected the use of a time trend (and other 'dynamic factors' e.g. time dummies) in its base

[138] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.183.
[139] 'RIIO-3 DD – Electricity Transmission'. Ofgem (July 2025); paragraph 5.100

expenditure models, arguing that it 'prefer[s] to focus on cost drivers that are exogenous and have a clear engineering, operational and economic rationale'.[140]

2.3.5 The negative coefficient on the time trend implies that expenditure is reducing at a rate of c. 4% p.a. It is important to note that this does not necessarily imply that TOs have been efficiently reducing costs at this rate, since some of this reduction could be explained by delayed investments due to a lack of funding or operational challenges including government delays and supply chain issues. Nevertheless, this effectively imposes a cost reduction challenge of 4% p.a. on all TOs, on top of Ofgem's Ongoing Efficiency (OE) challenge (of 1% p.a.). Therefore, the time trend double counts OE, since it would capture historical trends in costs attributed to industry-wide productivity gains (which would already be captured by the OE challenge). As such, TOs are currently set an unjustified overall OE challenge of 5.0% p.a. for CAIs, which is materially above any equivalent challenge applied in similarly regulated industries.[141]

2.3.6 Although Ofgem typically includes a time trend in its econometric models, it does so only when models are estimated using a combination of outturn and forecast data and when modelling a structural break in the time trend (i.e. a separate time trend for forecast and outturn data). In this way, Ofgem's models can (at least partially) account for any step-changes in expenditure between outturn and forecast, and do not directly rely on extrapolating historical cost trends. However, when regulators rely exclusively on outturn data (as Ofgem has done when modelling indirect expenditure), it is rarer to include a time trend. For example, at PR19 and PR24, Ofgem did not include a time trend in its econometric models. Indeed, at the PR14 redetermination, the CMA replaced Ofwat's time trend with time dummies, which do not impose an annual cost reduction target.

2.3.7 The coefficient of the time trend also has a wide confidence interval, from an implied c. 17% p.a. reduction in costs over time to an implied c, 8% p.a. increase over time. With such a range spanning across different signs with high magnitudes, it would be an error to incorporate and rely on the coefficient of the time trend to set allowances, since it cannot be statistically proven that the coefficient is different from zero, let alone negative or positive. Furthermore, the removal of the time trend has a negligible impact on model quality. Removing the time trend results in a minimal reduction in model fit, but the range of estimated efficiency scores narrows on both an outturn and a forward-looking basis.

2.3.8 This evidences that Ofgem's DD model may be overfitted to the historical data, a feature that is misaligned with Ofgem's own model development in other sectors, since it makes the results unreliable.[142]

2.3.9 Overall, the inclusion of this time trend alone results in a £107m reduction in the modelled costs based on the regression, and a £51m reduction in our baseline CAI allowance after the application of the 50:50 weighting and OE. For the reasons outlined above, the time trend must be removed from the CAI model. This conclusion is supported by the analysis of Economic Insight outlined in Annex 3.2[143].

Impact of NGET/NGGT on model performance

2.3.10 Another factor which supports the view that the models are over-fitted is the fact that the statistical performance of the models deteriorate significantly when NGET and/or NGGT are removed from the sample. This reflects the fact that Ofgem's modelled costs are largely driven by differences in the scale of the companies. This point is highlighted by the results in Table 2-3 below where, in the case of CAIs, the model fails three statistical tests (RESET, heteroskedasticity and normality) when NGET is removed. In the case of BSCs both the constant and the CSV are statistically

[140] Ofwat (2025), 'PR24 FD: Expenditure allowances - Base cost modelling decision appendix', December, p. 27.
[141] Ofwat at PR24 imposed an overall ongoing efficiency challenge of 1.0% p.a.
[142] Ofgem (2025), 'RIIO-3 DD – Gas Distributions', p.102, 5.50.
[143] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August, Section 3F, p. 35-36 including Table 11.

significant, and the model passes the heteroskedasticity and normality tests, but it fails the RESET test at 5 per cent significance level suggesting the model has used an incorrect functional form. Conversely, removing the Scottish TOs from the sample has a smaller impact on model performance, thereby reinforcing their sensitivity to scale. This is explained in further detail in the analysis from NERA presented in Annex 3.1[144].

Table 2-3 - Regression Results of Ofgem's CAI and BSC Models on SPT and SHET Only

	CAI	BSC
Coefficients		
Constant	-2.26	3.89**
CSV		1.22**
Capex	0.14	
MEAV	0.63	
Time trend	-0.03	
GT dummy		
Statistical tests		
RESET	0.060*	0.001***
Heteroskedasticity	0.008***	0.817
Normality	0.014**	0.461
Adjusted R squared	0.14	0.4
Number of observations	22	22

*Note: *** p < 0.01, ** p < 0.05, * p < 0.1.*
Source: NERA Reproduction of Ofgem Models.

2.3.11 NERA has also found that Ofgem's modelled costs from the econometric analysis are very sensitive to the level of costs for both NGET and NGGT. Overall, NERA's analysis indicates that Ofgem's models are driven by differences in scale rather than the relationship between indirect costs and cost drivers. The same pattern can be seen in the large differences present in efficiency scores i.e. rather than being ascribed to genuine efficiencies, the models are unable to control for the wide differences between the scale of TOs' operations. This is a fundamental weakness in the current modelled indirect costs.

2.3.12 This issue is addressed in further detail in the supporting paper from NERA which is provided in Annex 3.1[145].

Selection of cost drivers

2.3.13 Ofgem has used MEAV and Capex as the cost drivers of CAIs in its DD model. We have concerns with this selection, as follows.

MEAV

2.3.14 As noted above, MEAV in itself is not a proxy for the amount of new investment required on the network and is therefore not a good proxy for the CAIs related to those investments which will be required in RIIO-T3. We note that one approach that was considered for addressing this was to

[144] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.2.5, p17-19.
[145] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.2.5, p18 (Table 3.3).

include a lead on MEAV. However, having carefully assessed the merits of this approach we do not consider it would add to the robustness of the analysis at current stage.[146] Instead, we consider that capex and FTEs better reflect the growth that is required and thus a more appropriate solution would be to place a greater weighting on those parameters.

Capex

2.3.15 Capex has a strong relationship with CAI and in particular very CAI (Project Management and Network Design and Engineering) and should be retained as a key cost driver with an appropriate weighting to reflect its relative importance.

FTEs

2.3.16 Salary costs make up c.86% of our forecast CAI expenditure for RIIO-T3. In building up our Best View forecasts on a bottom-up basis we have considered the resources and FTEs required for each of the activities. This analysis shows that there is not a one-to-one relationship between FTEs and the size of a project. All face a different combination of challenges including obtaining planning consents, undertaking environmental studies, stakeholder engagement etc. As a result, all projects have different levels of complexity which must be accounted for in determining the associated resource requirements and ultimately the required costs. Ultimately, as a company grows it needs more FTEs to support growth. As a result, FTEs exhibit a strong relationship with CAIs and this should be reflected in its weighting.

Statistical evidence

2.3.17 The table below shows the correlation[147] between CAIs and these cost drivers over different time periods.

Table 2-4 - Correlations between cost drivers and CAI costs across different time periods

	2014–2024 (outturn)	2025–2031 (forecast)	2014–2031 (full period)
MEAV	0.94***	0.24	0.77***
CAPEX	0.72***	0.49**	0.68***
FTE	0.95***	0.38*	0.81***

Note: The correlations have been calculated using logarithmic transformations of CAI and cost drivers, as per Ofgem's model. ***p<0.01, **p<0.05, *p<0.10

2.3.18 On an outturn basis, MEAV has a strong correlation with CAIs. However, on a forecast basis, MEAV has no statistically significant correlation with CAIs. However, Capex and FTEs retain a statistically significant correlation with CAIs when focusing on forecast data, suggesting that these drivers may better reflect forward-looking cost pressures.

2.3.19 Given the operational arguments and statistical evidence outlined above, we consider that:

- MEAV should continue to be used as a driver but any measure of MEAV should have a suitably low weight in the regression modelling; and

[146] We identified a number of practical challenges with using a lead message for MEAV notably: (1) the arbitrary nature of determining an appropriate lead length; (2) the challenge of forecasting MEAV beyond RIIO-T3; and (3) MEAV is not, in itself, a reasonable proxy for CAI costs. At present the combination of these factors undermines the value of adopting MEAV with a lead measure.

[147] There are limitations with univariate correlation analysis (e.g. cost drivers may perform poorly in isolation, but well when considered alongside other cost drivers). The correlation analysis presented here should be interpreted qualitatively.

- FTEs and CAPEX should be given a higher weight in the models (currently, CAPEX receives a low weight and FTEs receives no weight at all).

2.3.20 Such changes would better capture forward-looking cost pressures and would therefore provide a more robust assessment of our efficient expenditure requirements.

Economies of scale

2.3.21 Both MEAV and Capex can be interpreted as 'scale variables': MEAV measures the size of a company's asset base and Capex measures the size of a company's investment programme. As such, the sum of the estimated coefficients on MEAV and Capex are a measure of economies of scale. The coefficients sum to 1.16, suggesting that there are material and statistically significant diseconomies of scale e.g. a 10% increase in scale is associated with a c.12% increase in CAI costs. This outcome is not aligned with operational expectations. As natural monopolies,[148] TOs should exhibit economies of scale (i.e. sum of coefficients below 1) or, at most, constant returns to scale (i.e. sum of coefficients equal to 1).[149] This unintuitive finding leads to a biased assessment of TOs expenditure requirements, with smaller TOs being underfunded and larger TOs being overfunded, since larger TOs have disproportionately higher costs.

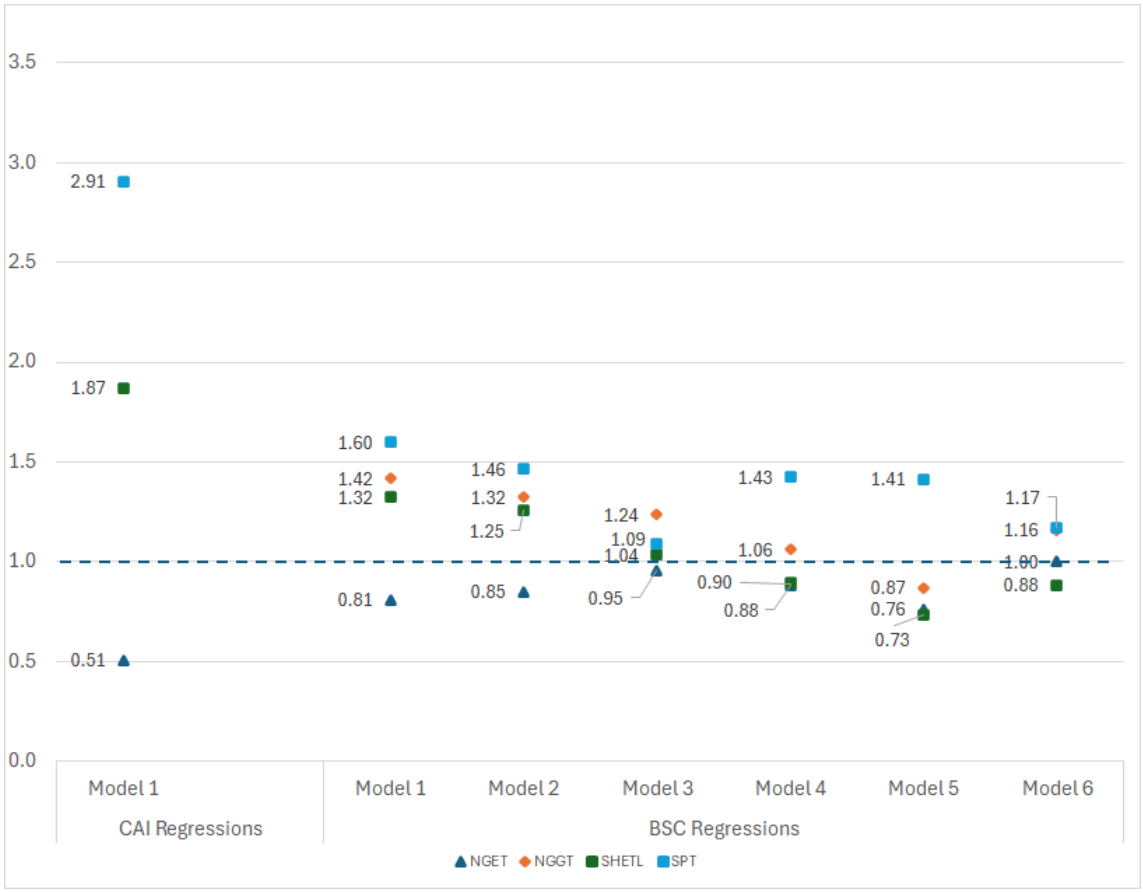
2.3.22 Ofgem should assess whether its models lead to operationally intuitive outcomes, including in relation to economies of scale. If an otherwise robust model estimates diseconomies of scale, it should explore why this is the case. For example, if smaller TOs are more efficient (i.e. lower cost), this would distort the estimated relationship between scale and costs, resulting in the appearance of diseconomies of scale. The models may also omit relevant drivers of expenditure that are historically correlated with scale, again resulting in a distorted relationship between scale and costs. Indeed, when NGET is removed from the sample, the sum of coefficients is less than one, implying that there are economies of scale. Ofgem should consider constraining the model to be constant returns to scale to ensure that TOs are not unduly penalised or rewarded on account of their size.

Large range of efficiency scores

2.3.23 We consider the range in RIIO-ET3 efficiency scores from Ofgem's regression analysis does not satisfy a common-sense plausibility check. The following figure summarises the distribution of efficiency scores across all TOs in Ofgem's regression modelling, including BSC models that were trialled but not implemented.

[148] Natural monopolies have large 'fixed' costs that do not increase (or increase slowly) as scale increases. This reduces the 'average cost' as scale increases.
[149] A Cobb-Douglas function is a common way to model the relationship between inputs (like labour and capital) and output. It determines that when the sum of the coefficients (exponents) of the inputs equals 1, it represents constant returns to scale. At RIIO-ED2, all of Ofgem's econometric models either estimated economies of scale or constant returns to scale, as does Ofgem's Totex model for GD3. See Ofgem (2022), 'RIIO-ED2 FD Core Methodology Document', November, tables 68 and 69; and Ofgem (2025), 'RIIO-3 DD – Gas Distribution', July, table 27.

Figure 2-4 - RIIO-T3 efficiency scores from Ofgem's regression modelling



Source: SPEN analysis.

2.3.24 The efficiency score of 2.91 for SPT means that our forecasts for RIIO-ET3 are 2.9 times Ofgem's modelled costs. Such an efficiency score is infeasible, particularly given:

- We are the most efficient TO on a historical outturn basis (efficiency score 0.95) - it is infeasible that our proposed expenditure in RIIO-3 is c. three times less efficient than our outturn given we are driving the efficiency frontier
- the results from the ratio benchmarking suggests that our expenditure proposals are efficient; and
- the efficiency score of 0.51 for NGET, indicating Ofgem's modelled costs are double that of NGET's own forecast costs (as noted above, this could be due to the diseconomies of scale estimated in the model).

2.3.25 This highlights the underlying modelling issue in that the baseline drivers do not account for the growth required for SPT, and not revising this for FD would result in material underfunding.

2.4 Alternative CAI approaches

2.4.1 Given the limitations and flaws we have identified, we have developed a set of pragmatic alternative approaches to enable reasonable allowances for CAIs for RIIO-T3. We consider that the correct approach (Preferred Approach 1) is to conduct a Best View Regression analysis, but has also considered two alternatives (Alternative Approaches 2 and 3) below which could improve the modelling principles and mitigate the impact on allowances:

Preferred Approach 1: Forward-looking Best View Regression analysis

2.4.2 Given the issues that we have demonstrated with the historical regression, Ofgem should prioritise using appropriate, forward-looking, cost drivers including FTEs and Capex. Ideally, this should be on Best View basis including new information [redacted]. This is our preferred approach. We consider that adopting Best-View is the optimal approach as it addresses the root of the problem i.e. fully reflecting the required CAIs to support growth, rather than trying to mitigate the impact through changes to the modelling.

Alternative Approach 2: Sequential application of methods

2.4.3 Currently, Ofgem uses the two methods (econometric analysis and ratio benchmarking) to construct two independent forecasts of companies' expenditure requirements. The econometric analysis provides a comparative assessment of TOs expenditure based on historical data. While the model explains differences in costs reasonably well on an outturn basis, it cannot account for forward-looking cost pressures. Meanwhile, the ratio benchmarking can account for forward-looking cost pressures but does not provide a comparative assessment. As the two methods currently achieve different purposes (one is entirely backward-looking, the other is more forward-looking), taking an average is inappropriate. It is feasible to try to combine the advantages of both methods while seeking to mitigate the disadvantages (to the extent possible) by applying the methods sequentially, rather than taking an average across the two methods.

2.4.4 Specifically, Ofgem's econometric model (without the time trend and with the period extended to include the forecasts for 2025 and 2026) can be used to derive an efficient cost prediction for 2024–26.[150] This efficient cost prediction could then be rolled forward into RIIO-T3 to account for growth. For example, by adjusting for the percentage change in FTEs between 2025 and 2026, 2026 and 2027 etc. Note that it would be important to account for economies of scale when applying this growth factor—we would expect a 1% increase in FTEs to have a less than 1% impact on our expenditure requirements. We consider that a scaling factor of 0.67 would account for their not being a 1 to 1 relationship between FTEs and indirect costs. The adjustment factor of 0.67 is consistent with the average coefficient on FTEs across 6 indirect regressions which include FTEs as cost driver and is also in line with the proportion of labour costs within our total indirect costs excluding contractor indirects (circa 66.5%).

2.4.5 We consider FTEs is the most appropriate cost driver to account for growth as there is a strong correlation with CAIs on both an outturn and forward-looking basis. We do not consider that MEAV is an appropriate cost driver to account for growth, for the reasons outlined above. CAPEX may also be a relevant driver of growth and could be considered alongside FTEs.

2.4.6 We also consider that the starting point for applying growth should be earlier than 2026. A large proportion of the planned growth in FTEs and indirects is required in the last two years of RIIO-T2 (2025 and 2026) for us to have a suitably scaled organisation to manage the RIIO-T3 investment programme.

Alternative Approach 3: Improving the econometric model and increasing the weight on ratio benchmarking for both the Scottish TOs

2.4.7 Ofgem's historical regression analysis results in a 49% decrease in modelled costs between RIIO-T2 and RIIO-T3 while the ratio analysis results in a 53% increase. The current 50:50 weighting means that the growth in RIIO-T3 is virtually cancelled out. This further alternative proposal involves minor amendments to the econometric analysis, and increasing the weighting on the ratio analysis. The specific amendments to the CAI model follow the critique outlined in the sections above, namely:

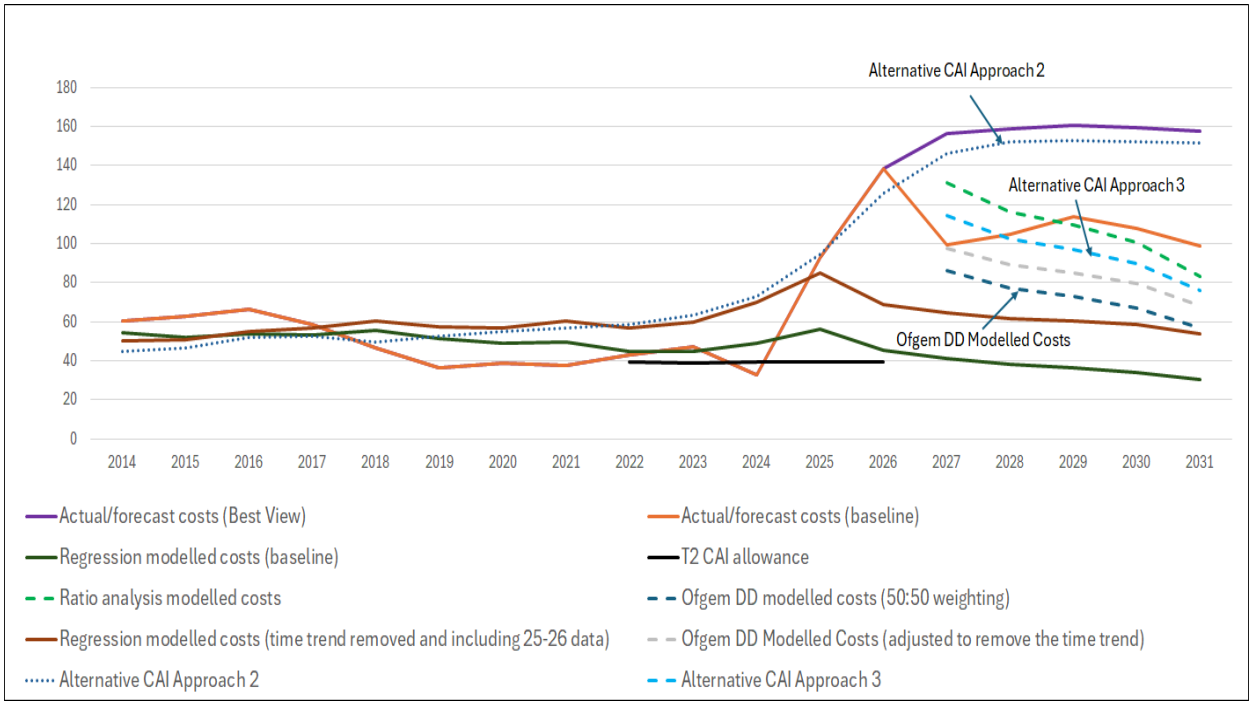
[150] From a technical perspective, it may be better to use the regressions to estimate average efficient modelled costs for 2022 to 2024 and then roll forwards from this point as it avoids the use of the historical regressions to estimate forecasts costs. However, we've chosen the average of 2024-26 as the starting point for growth as it's better aligned with Ofgem's options with its trend analysis

- extending the data for Ofgem's DD regression to include data 2024-25 and 2025-26;
- removing the time trend to avoid the overlap between the cost modelling and the application of OE; and
- considering two models, one which controls for FTEs as a cost driver and one which controls for FTEs and MEAV as cost drivers.

2.4.8 Although these models represent an improvement on the DD model, they cannot fully capture the step-change in expenditure requirements that are required in RIIO-3, which justifies placing higher weight on the ratio benchmarking. For example, we have modelled the impact of applying a 75% weighting to the ratio benchmarking that is more robust and better reflects the required growth for both Scottish TOs. A 25% weighting would be applied to the improved econometric models outlined above. From a technical perspective, it would be better to address the issues in the econometric benchmarking directly (e.g. by incorporating forecast data in the models, including drivers that can capture the step-change in requirements), which could then (in principle) justify having a more balanced weighting between the two methods. However, given the current inconsistencies in data reporting (outlined in Alternative 2 above), we do not consider that it is feasible to robustly develop models on a forward-looking basis at this stage.[151] Placing more weight on the ratio analysis provides a simpler alternative, which still raises the importance of accounting for the step-increase in growth anticipated by Scottish TOs.

2.4.9 The figure below shows the impact of two of these proposed alternatives for CAIs. The dark blue dotted line shows the modelled costs for **Alternative Approach 2**, while the light blue dashed line shows the modelled costs for **Alternative Approach 3**. At this stage, it is not possible to include the results of **Preferred Approach 1** within the chart, but we will provide an update once the relevant information is available [redacted].

Figure 2-5 - Impact of proposed CAI alternatives for estimating modelled costs for RIIO-T3



2.4.10 Our proposed **Alternative Approach 2** is between the Baseline Forecast and the Best View for RIIO-T3. It results in a £395m increase in Ofgem's DD modelled costs to £755m before the

[151] Under the current cost and cost driver forecasts, the statistical quality of our models does not deteriorate when forecasts are included.

application of separately assessed costs or OE. **Alternative Approach 3** would result in a £120m increase in Ofgem's DD modelled costs to £480m before the application of separately assessed costs or OE.

2.4.11 **Preferred Approach 1** is our preferred solution on the basis that Best View analysis will provide the most robust outcomes. In the absence of Best View information, we consider **Alternative Approaches 2 and 3** provide pragmatic solutions to addressing the flaws that we have demonstrated exist in DD.

2.5 Adjustment mechanisms for CAI

2.5.1 We recognise that a further CAI UIOLI allowance of £78m will be provided up-front for CAPEX projects falling under uncertainty mechanisms. This is a positive proposal which we welcome, however, it would still leave a significant proportion of our required CAIs unfunded.

2.5.2 We have concerns about how the total value of the UIOLI pot has been calculated and ultimately, given the difference between this value and our business plan, whether it will enable the investment required to support our anticipated growth in RIIO-T3. We consider that the solution lies within the scope of what Ofgem has proposed by determining more appropriate parameters and that ultimately this will be in the interests of GB consumers by ensuring efficient investment at the right time.

2.5.3 Ofgem has applied a 10% ratio to direct capex for relevant projects to establish the £78m UIOLI for us without providing an adequate evidence-based explanation or indeed associated justification for its decision to adopt 10%. There are at least three sources of information that suggest this figure should be higher and closer to c. 15%, these are:

1) A CAI-to-capex ratio of 14.1% derived based on a CAI regression model estimated in levels and with outturn data specific to the ET sector which is consistent with Ofgem's approach at RIIO-ED2 when it set the indirect scaler
2) Using a ratio of 15.60% obtained from a CAI regression specified in logs that excludes SHET in 2021 as it is an outlier, where the coefficient for capex is equal to 0.23
3) The 13.42% ratio used in the opex escalator for RIIO-T2

We consider the first two models to be more robust with further detail provided in the report from NERA in Annex 3.1[152]. However, taken together all of these models support a higher figure and merit a more detailed review and consideration by Ofgem.

2.5.4 Ofgem has also proposed no UIOLI for capex projects below a £25m threshold. There will be a substantially increasing volume of demand and generation projects in RIIO-T3 that will fall below this threshold. Excluding these schemes is arbitrary without providing reasons and evidence supporting this difference in treatment and in essence represents an additional OE over and above the 1% per annum Ofgem is proposing.

2.5.5 The proposed treatment of CAIs is also inconsistent with other aspects of the RIIO framework. The Load UIOLI would only include projects if their value was greater than £25m, so there is no logic for excluding projects below this value from the CAI UIOLI. There is a direct parallel with MSIP projects in RIIO-T2 which were subject to the Opex Escalator. It is also notable that the NARM funding mechanism didn't provide a separate CAI adjustment with under and over delivery again subject to the Opex Escalator. With the exception of where there are already mechanisms in place to provide bespoke CAI funding there is, therefore, no precedent for exclusions from the CAI UIOLI and Ofgem has not provided evidence which supports the need for the proposed exclusion and change in approach.

[152] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.4.5, p36-38.

2.5.6 Finally, we note that Ofgem references that it would consider a mechanism for indirects funding "for load related projects where the full CAI UIOLI has been utilised[153]." We welcome this but this mechanism needs to be fully fleshed out.

2.5.7 We have identified six changes outlined below which require to be implemented at FD to ensure the mechanism will work effectively and deliver the necessary growth:

1. **The ratio used to calculate CAI UIOLI for relevant projects should be increased from 10% to c. 15%** – This higher percentage is still conservative but is supported by stronger evidence (see NERA's report in Annex 3.1[154]).
2. **The £25m threshold for capex project should be removed** – This reflects the fact that CAI resources are required for all projects, and their requirement is not a direct reflection of materiality but rather will vary by complexity. These cannot be delivered by existing resources which will be at full capacity. The implications of this threshold can be shown in the table below which shows that for us only 30% of projects would fall within the thresholds proposed for the mechanism. In part, this reflects the fact that the inclusion of 132kV means the Scottish TOs have a higher volume of smaller connections i.e. those below the £25m threshold. Ultimately, this in itself demonstrates the application of an arbitrary cap across all TOs has no correlation with the need for CAIs. The removal of the cap would be much more consistent with a mechanism designed to provide the investment required to drive growth by enabling the resources that will be critical to delivering that investment.

Table 2-5 - Impact of thresholds on the UIOLI pot

	# of Projects				% of Projects			
	<£25m	>£25m and <£150m	>£150m	Total	<£25m	>£25m and <£150m	>£150	Total
T3 BPDT	88	43	10	141	63%	30%	7%	100%

3. **The £150m threshold for determining the scope of the allowance should be reviewed with exclusions only required for mechanisms with bespoke CAI funding** – This is to ensure it aligns with other relevant thresholds such as those for ASTI and tCSNP projects. This will be critical to 'right-size' the resources to deliver the required investment. Again, the implications of this for us can be seen from the table above. All projects require adequate resource in order to ensure their successful delivery and on this basis, the only exclusions should be for mechanisms with bespoke CAI funding.
4. **The mechanism should recognise where projects span price control periods** – It does not make sense to only include projects whose delivery falls entirely within RIIO-T3. In reality, there will be overlap between RIIO-T2 and RIIO-T3 and indeed between RIIO-T3 and RIIO-T4. The mechanism should allow the required CAI resource to be accessed when required. This will be critical to timely delivery. The reporting arrangements can easily be adjusted to ensure the timing of investment is fully reflected and avoid double funding.
5. **A mechanism should be introduced that enables additional indirects funding where the full CAI UIOLI has been utilised** – The key issue is timing. It is critical to get the level of the UIOLI right from the start. Ofgem identified this in DD where it noted "We recognise that delivering CP2030 is likely to require an increase in activity during RIIO-ET3 and that TOs will need to prepare in advance[155]." We welcome this statement as a way of ensuring the UIOLI pot will be in place to meet the required investment. However, to ensure timely investment this mechanism should be mechanistic, available from the

[153] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.156, 5.131.
[154] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.4.5, p36-38.
[155] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.154, 5.123.

start of RIIO-T3 and be automatically triggered when the UIOLI pot reaches a designed level rather than relying on an additional process which would introduce unnecessary complexity and uncertainty. To ensure that all stakeholders have full transparency and certainty, the mechanism should be fully realised in FD and embedded in the licence drafting.

6. **Clarity should be provided on reporting requirements and how information will be assessed** – A lack of clarity regarding how the mechanism will operate in practice creates additional uncertainty. It is imperative that the mechanism is simple to use, and the required evidence base well understood to mitigate the risk of under-recovery.

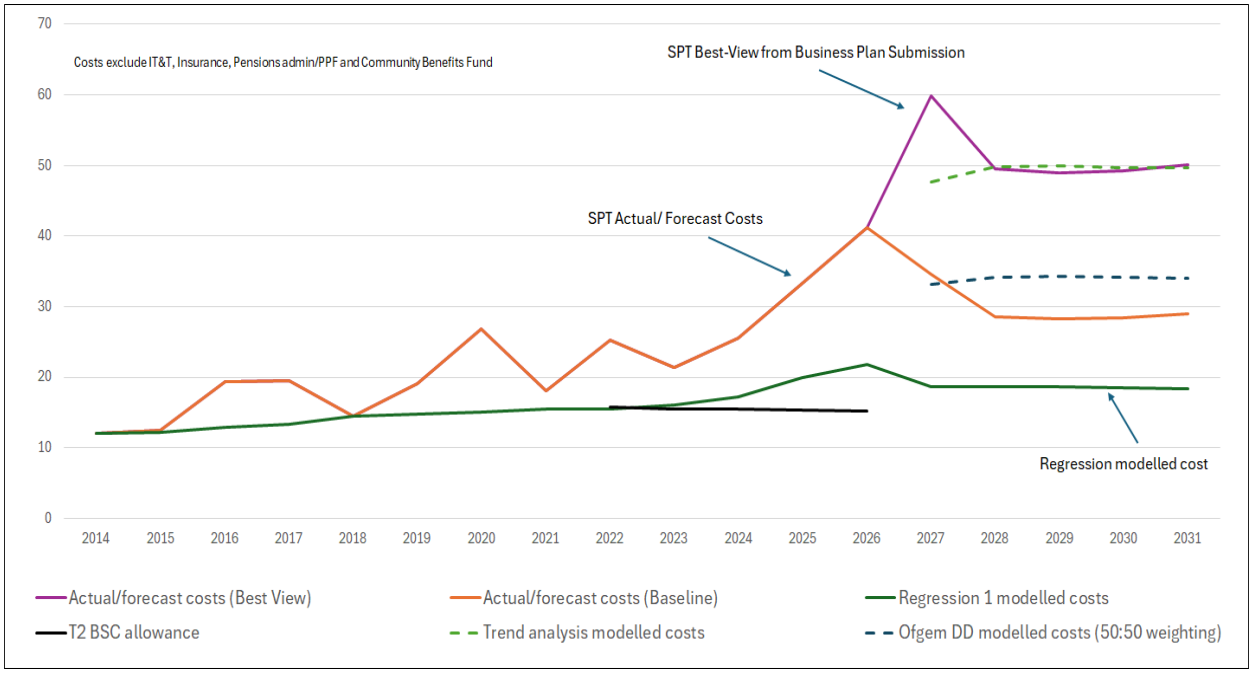
2.5.8 Taken together, all these measures would provide the most efficient outcome for customers by ensuring funding is only provided when required but also enabling timely investment to drive growth which will ultimately bring down bills and improve longer-term energy security. The importance of recognising the economic value of investment in providing value for money for customers is addressed in further detail in Chapter 7 – Value for Money.

2.6 Ofgem BSC Modelling

2.6.1 For RIIO-ET3, we are forecasting a step-increase of c. 238% in yearly total BSC costs relative to the yearly outturn costs of RIIO-ET2 (c. 163% when CBF is removed). As acknowledged by Ofgem, our step-increase in indirect costs reflects the current size of the company, and the different levels of growth required relative to other TOs to deliver our anticipated Capex programme.[156] Therefore, it is vital that Ofgem's BSC assessment is able to account for the differing levels of growth expected in RIIO-ET3.

2.6.2 The historical regression of BSC uses a Composite Scale Variable (CSV) comprising of MEAV, FTE and Totex, weighted 79.5%, 11.5%, 9.0% respectively as a single cost driver, alongside a Gas Transmission (GT) dummy variable. The regression is based on the outturn period 2013-14 to 2023-24. The following figure illustrates our actual and forecast baseline BSC costs, relative to the modelled costs from Ofgem's DD BSC model (and its trend analysis).

Figure 2-6 - BSC actual and forecasts costs relative to modelled costs



Source: SPEN analysis.

[156] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.144, 5.90.

2.6.3 As shown above, the modelled costs from the regression (green line) have been consistently below our costs on an outturn basis (orange line) for the period 2014–2024 as well as materially lower than our modelled Best-View (purple line). This discrepancy also increases on a forward-looking basis (2025–2031). As discussed in the overarching points, we agree with the principle of using multiple methods to inform cost assessment. However, the methods should provide a reasonably consistent estimate of forecast costs for the methods to be considered robust.

2.6.4 We note that there are material inconsistencies between the modelled costs for BSC and the econometric benchmarking. In particular, the modelled costs from the forward-looking trend analysis are almost three times higher than the modelled costs produced under the econometric benchmarking.

2.6.5 We consider the BSC regression analysis is not credible as: (i) it is inconsistent for us to be inefficient on an outturn basis in BSC, while being the first ranked in efficiency across CAI and other cost areas; and (ii) it fails to account for our step-increase in growth as demonstrated by the divergence between modelled costs in RIIO-ET3 and our forecast costs.

2.6.6 In particular, despite Ofgem acknowledging our step-increase in costs, due to the high levels of growth required to deliver our anticipated Capex programme, Ofgem's BSC models unintuitively predict our costs to increase gradually into RIIO-ET3, then eventually reduce towards the latter years of the regulatory period. Therefore, we consider Ofgem's regression analysis is not fit for purpose for the reasons set out in the following sections.

Bias from the reliance on a singular model

2.6.7 As discussed in section 2.2 Common Methodological Issues, Ofgem has opted to select a single 'best' model from a suite of alternative BSC models which appears to place significant weight on historical model fit, even though several of the alternative models have similar fits. The following table summarises Ofgem's suite of BSC models.

Table 2-6 - Statistical results from Ofgem's BSC regression modelling

	Model 1 (Ofgem DD)	Model 2	Model 3	Model 4	Model 5	Model 6
Time period	*2014–2024*	*2014–2031*	*2022–2031*	*2014–2031*	*2014–2024*	*2022–2031*
CSV (BSC)	0.84***	0.76***	0.54***			
FTE (log)				0.52**	0.72*	0.37*
MEAV (log)				0.47**	0.37	0.38*
GT dummy	-0.77***	-0.66***	-0.52***	-0.35**	-0.23	-0.37**
Constant	3.51***	3.57***	3.68***	-4.76**	-5.21**	-2.76*
Adjusted R-squared	0.87	0.82	0.79	0.86	0.88	0.84
RESET	0.075	0.001	0.001	0.043	0.043	0.721
Heteroscedasticity	0.01	0.001	0.039	0.003	0.235	0.01
Normality	0.201	0.184	0.001	0.406	0.297	0.001
Number of observations	44	72	40	72	44	40
Range in efficiency scores (outturn)	51%	45%	60%	45%	47%	63%
Range in efficiency scores (ET3)	79%	61%	13%	54%	68%	29%

Source: SPEN analysis from Ofgem's modelling files.

2.6.8 As shown above, Ofgem's selected model (Model One) does not have the highest model fit, fails the RESET test at the 10% significance level suggesting the model has a mis-specified functional form, fails the heteroskedasticity test at the 5% significant level, and results in the highest range in estimated efficiency scores across RIIO-ET3. The 79% range in efficiency score is particularly wide when compared with regulatory precedent. For example, at RIIO-2, the equivalent range was c. 37%, while at RIIO-ED2 (where Ofgem developed a separate model for CAIs) the range was c. 31%.[157]

2.6.9 Furthermore, relative to Model One:

- Model Four has a similar model fit, performs only marginally worse on the RESET test, but leads to a materially narrower range in efficiency scores.
- Model Five is similar to Model Four but has a higher model fit (while the coefficient on MEAV is statistically insignificant, the two coefficients across MEAV and FTE are jointly significant).
- Model Six has a marginally lower fit but performs materially better on the RESET test. It can also better capture the step-change in costs in ET3, given that it is estimated on forecast data and the range in estimated efficiency scores across ET3 is more plausible and aligned with regulatory precedent.

2.6.10 Therefore, on a statistical basis, Model One is not superior relative to other models, in particular to models that use FTE and MEAV as cost drivers instead of CSV. We consider the reliance on this single model for BSC is biased, since our modelled allowance at DD is based on the lowest

[157] Ofgem (2022), 'RIIO-ED2 FDs Core Methodology Document', November, Table 65.

in the range of the six BSC models from circa. £93m (Model One) to £137m. As a general point, we consider that Ofgem should utilise a range of sensible and robust models and triangulate across them to mitigate the risk of any biases, assuming that no single model is clearly superior (as is currently the case). This is consistent with Ofgem's approach to cost assessment at RIIO-ED2, as well as with other regulated industries.[158]

2.6.11 The merits of adopting a triangulation across BSC models within Ofgem's modelling suite is addressed in further detail in the report from Economic Insight provided alongside this response.

Incompatible CSV

2.6.12 Ofgem has retained its RIIO-ET2 CSV, and includes MEAV, FTE and totex as its components, with weightings 79.5%, 11.5% and 9.0% respectively. The table below shows the correlation between BSC and the CSV components over different time periods.

Table 2-7 - Correlations between CSV components and BSC across different time periods

	2014–2024 (outturn)	2025–2031 (forecast)	2014–2031 (full period)
CSV	0.85***	0.87***	0.82***
MEAV (79.5%)	0.78***	0.81***	0.74***
FTE (11.5%)	0.94***	0.82***	0.90***
TOTEX (9.0%)	0.79***	0.73***	0.80***

Note: The correlations have been calculated using logarithmic transformations of BSC and cost drivers, as per Ofgem's model.
***p<0.01, **p<0.05, *p<0.10

2.6.13 On an outturn basis, MEAV has a strong correlation with BSCs, although FTE has a materially stronger correlation. On a forecast basis, MEAV and FTEs have similarly strong correlations, with FTEs having a marginally stronger relationship. Over the full modelling period, FTEs exhibit the strongest relationship with BSCs, materially higher than the other drivers.

2.6.14 As such, we consider FTEs is as capable, if not more capable than MEAV to account for both historical and forward-looking cost pressures for the industry. Therefore, the materially lower weight set on FTEs relative to MEAV is unjustified and a biased assessment. As such, we propose two alternatives to the CSV construction, as follows.

2.6.15 While Ofgem sets its weightings based on cost activities mapped to each of the components, we consider this mapping to be inaccurate and arbitrary, particularly with regards to CEO and property management costs. CEO activity and costs will be driven by the size and complexity of the organisation rather than asset value. Two companies could have equal asset values but different organisational structures, number of employees to account for, geographic spread etc. such that a CEO of a more operationally complex company would necessitate greater compensation, independent of MEAV. Property management will also scale more with the number

[158] For example, Ofwat used 24 econometric models to assess wholesale water base expenditure at PR24. See Ofwat (2024), 'PR24 Final Determinations: Expenditure allowances - Base cost modelling decision appendix', December, appendix A2.1.

of employees due to the requirement of bigger control centres and offices, not with the value of network infrastructure (e.g. transformers and substations).

2.6.16 The re-weighted CSV also improves upon Model One. While the model quality in terms of adjusted R-squared relative to Ofgem's DD model is not significantly affected, the distribution in efficiency scores is materially narrower both on an outturn and forecast basis, as the range in efficiency scores is reduced by c. 11 percentage points and 17 percentage points respectively. Therefore, should Ofgem decide to retain a CSV approach at FD we consider the aforementioned costs should be moved to the FTE component, and more weight should be given towards FTEs relative to MEAV in a CSV.

2.6.17 As an alternative, Ofgem could consider weighting the three cost drivers (MEAV, FTE and TOTEX) using multivariate regression analysis, where the weight attached to each cost driver is informed by the estimated coefficient. This avoids the need for mapping activities within BSC to a single cost driver (which could be at least somewhat subjective) and is broadly aligned with Ofgem's approach to constructing CSVs at RIIO-ED1.

2.6.18 The resulting weights on the two approaches are shown in the table below.

Table 2-8 - Proposed regression-based weights for BSC cost drivers

	FTE	MEAV	TOTEX
Ofgem (ET3 DD CSV)	11.5%	79.5%	9%
Improved operational mapping	55.6%	35.4%	9%
Regression-based weights	67%	27.5%	5.5%

2.6.19 The higher weight attached to FTEs is aligned with operational expectations (under the improved mapping) and statistical evidence (under the regression-based weights). It is important to note that while a higher weighting on FTEs within the CSV would allow for the model to better account for the step-increase in growth relative to Ofgem's DD CSV, the ability of FTEs to account for this growth is still suppressed by a material weighting on MEAV, and the reductions in FTEs applied by Ofgem in estimating baseline FTEs.

2.7 Alternative BSC approaches

2.7.1 Given the limitations and flaws we have identified, we have developed a set of pragmatic alternative approaches to enable reasonable allowances for BSC for RIIO-T3. We consider that the correct approach is to conduct a Best View Regression analysis, but we have also considered alternatives below which could improve the modelling principles.

Preferred Approach 1: Forward-looking Best View Regression analysis

2.7.2 In line with CAIs, our preferred approach is for Ofgem to carry out forward-looking regression analysis with appropriate cost drivers including FTEs, Capex, Totex and MEAV. Ideally, this should be on Best View basis.

Alternative Approach 2: Sequential application of methods

2.7.3 Currently, Ofgem uses the two methods (econometric analysis and trends analysis) to construct two independent forecasts of companies' expenditure requirements. However, it is feasible to

combine the comparative assessment intrinsic to the econometric analysis while also incorporating the forward-looking assessment intrinsic to the trends analysis, or another forward-looking method such as the ratio benchmarking akin to the CAI approach.

2.7.4 Specifically, a triangulation of several econometric models (Models One, Four, Five, and Six) can be used to derive an efficient cost prediction for 2024–26.[159] This efficient cost prediction could then be used as the starting point for growth in RIIO-ET3. Ofgem can then then roll the average 2024-26 efficient modelled cost forwards to take account of growth. For example, by adjusting for the percentage change in FTEs between 2025 and 2026, 2026 and 2027 etc moderated by a scaling factor of 0.67 to account for there not being a 1 to 1 relationship between FTEs and indirect costs.

2.7.5 As noted above for CAIs, we consider FTEs is the most appropriate cost driver to account for growth as there is a strong correlation with BSC and it provides a more balanced picture than either MEAV (relatively flat) and Capex (very high growth). The adjustment factor of 0.67 is consistent with the average coefficient on FTEs across 6 indirect regressions which include FTEs as cost driver and is also in line with the proportion of labour costs within our total indirect costs excluding contractor indirects (circa 66.5%).

Alternative Approach 3: Increase the weighting on the forward-looking ratio benchmarking for both the Scottish TOs

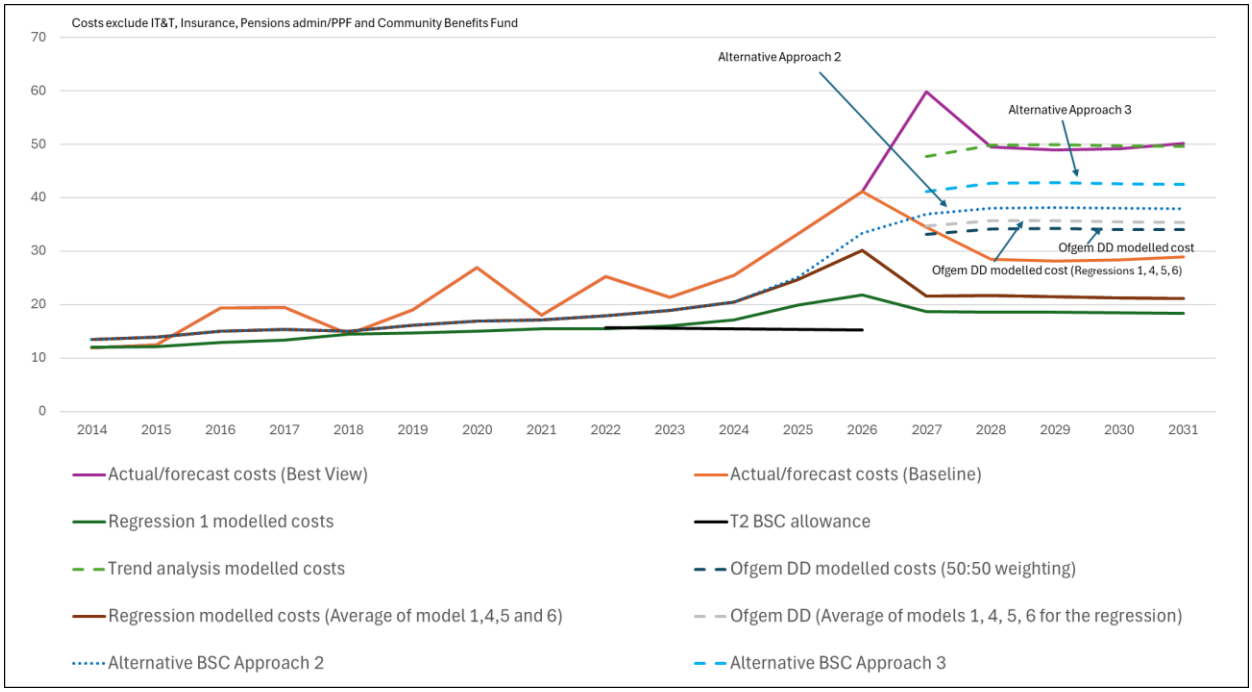
2.7.6 Ofgem's historical regression analysis results in a 3% increase in modelled costs between RIIO-T2 and RIIO-T3 while the trend analysis results in a 68% increase. The current 50:50 weighting means that forecast growth for RIIO-T3 from the trend analysis is halved to c. 35%, which is materially below our expected growth. If the regression analysis cannot be adequately remedied, Ofgem should increase the weighting on the forward-looking analysis. For example, we have modelled the impact applying a 75% weighting to the trend analysis that better reflects the required growth. A 25% weighting would be applied to the average modelled costs from Models 1, 4, 5 and 6. While from a technical perspective it would be better to address the remaining issues in the benchmarking directly, this provides a simpler approach, which still raises the importance of accounting for the step-increase in growth anticipated by Scottish TOs.

2.7.7 In respect of both Alternative Approaches 2 and 3, the starting point for applying growth should be earlier than 2026. A large proportion of the planned growth in FTEs and indirects needs to happen in the last two years of RIIO-T2 for us to have a suitably scaled organization to manage the RIIO-T3 investment programme. This is important as Ofgem itself has recognised that TOs "are at different stages of preparedness to meet CP2030 targets" with growth during RIIO-T3 critical to our delivery.

2.7.8 The following figure below shows the impact of the alternative approach for BSC. The dark blue dotted line shows the modelled costs for **Alternative Approach 2**. The light blue dashed line shows the modelled costs for **Alternative Approach 3.**

[159] From a technical perspective, it may be better to use the regressions to estimate average efficient modelled costs for 2022 to 2024 and then roll forwards from this point as it avoids the use of the historical regressions to estimate forecasts costs. However, we've chosen the average of 2024-26 as the starting point for growth as it's better aligned with Ofgem's options with its trend analysis

Figure 2-7 - Impact of proposed BSC alternative approaches for estimating the modelled costs for RIIO-T3



Source: SPEN analysis

2.7.9 **Alternative Approach 2** would increase the modelled costs relative to Ofgem's DD position by £18m to £189m before the application of separately assessed costs or OE. **Alternative Approach 3** would increase the modelled costs by £40m to £212m before the application of separately assessed or OE.

2.7.10 As with CAIs, our preferred solution is **Preferred Approach 1** on the basis that Best View analysis will provide the most robust outcomes. In the absence of Best View information, we consider **Alternative Approaches 2 and 3** provide pragmatic solutions to address the flaws in the proposed approach that we have demonstrated exist in DD.

2.8 Separately Assessed BSC

2.8.1 Ofgem's lack of transparency surrounding its review of IT&T costs raises major concerns about the correctness and robustness of its process in reaching its proposals, which are a significant reduction on our funding request. Business Support IT&T costs[160] were subject to a 51% reduction, with £43.5m approved of the £84.5m submitted. In the absence of clear reasons, it is hard to reconcile the major reduction in costs allowed. The aforementioned costs were grouped and subject to expert review. We set out our reasons why we disagree with the assessment approach in further detail in Section 4.2 Operational Technology.

2.8.2 It is positive that Ofgem recognises the need to separately assess Insurance costs and that the primary reason for the cost increase in RIIO-T3 relates to undersea cables. Whilst Ofgem acknowledges a separate assessment of undersea cables may be appropriate it was not proposed in DD as it did not fit with their chosen methodology.

2.8.3 Benchmarking against onshore network length (a combination of OHL (vast majority) and UGC (minority)) is not appropriate as length is not a key cost driver, instead the key factors are the risk and cost associated with the installation and operation of the subsea cables and potential repairs.

[160] BSC IT&T was excluded from Ofgem's indirect cost modelling and subject to expert review. It was grouped with other IT&T costs including Operational Technology (Table 8.9 (£123.834m)) and a subset of Non-operational Capex (Table 9.1 rows 30 & 31 (£5.477m)). This group of costs was then subject to separate expert review.

We went to market early this year to get a quote to add Western Link into the offshore policy for operations. The quote we obtained was a cost of [redacted] per annum with a [redacted] deductible per claim. This compared with a cost of insuring the entire SPEN (SPT+SPD+SPM) network of £[redacted]m per annum with a per claim deductible of only £[redacted]m. It is clear that the market is not valuing this on a network length basis.

2.8.4 The cost of insuring undersea cables must be reconsidered and treated as a separate case at FD due to the hostile environment in which they are located. For example, vessels are required for installation, which are limited in supply which therefore drives up costs. The number of suppliers capable of undertaking such installation work is also a factor which increases costs – there are far fewer contractors able to go offshore and install cables, than can do this onshore. There can be major variations between subsea cable projects, for example if one subsea cable is in deeper water than another (requiring larger vessels) or has different seabed conditions along the cable route than another cable. Weather is a factor – repairs expected to take 10 days could take double that if there is no suitable weather window, and the TO will be paying standby costs in the meantime. The costs of such insurance are competitively tendered as evidenced in our Business Plan submission.

2.8.5 Another potential option on insurance, which was raised in CAWG 22, was to have a reopener should a material risk occur relating to subsea cables occur. We would require further engagement with Ofgem on this proposal to ensure any reopener is fit for purpose.

2.9 Adjustment mechanisms for BSC

2.9.1 The proposed RIIO-T3 reopener mechanism does not currently provide appropriate protection for us for a material increase in BSC.

2.9.2 We have identified the following four changes to the mechanism which should be made at FD to ensure the mechanism operates effectively for all TOs and in the interests of consumers by providing an appropriate balance of risks:

1. **The application window should be early in RIIO-T3 (Years 1 or 2) or based on an automatic trigger** – BSCs are not a consequence of investment but a critical driver of delivery, especially given BSCs are mostly driven by the required FTEs. The mid-period timing of the reopener outlined in DD would deliver additional funding too late during the price control period as the funding would only feed through in Year 5 of the price control. An automatic trigger would be better as it would recognise that different TOs may require additional BSC at different points in the RIIO-ET3 period. This conclusion is supported by the findings of Economic Insight set out in Annex 3.2[161].
2. **The reopener threshold should just be based on BSC costs** – The proposed application of a totex threshold (non-variant totex) for the BSC reopener creates an unintended consequence that if a TO achieves significant efficiencies on another area of cost such as non-load related capex or NOCs, the TO may then be unable to trigger the BSC reopener. This effectively undermines the intended purpose of the TIM to drive improvements in efficiency. Based on our calculations, even if SPEN spent in line with its Best View forecast for BSC, it would not be able to trigger the reopener because the value would not reach the much higher totex trigger point. This conclusion is supported by the findings of Economic Insight set out in Annex 3.2[162].
3. **There should be a BSC UIOLI pot that is trued up as part of the BSC reopener** – While Ofgem has raised concerns about a UIOLI mechanism not being practical for BSC, we do not agree with this conclusion. Higher capex drives a greater requirement for CAI

[161] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August, Section 2H, p. 27-28.
[162] Economic Insight (2025), 'RIIO-3 DD Indirect Costs Assessment: Report for Scottish Power Transmission,' August, Section 2H, p. 27-28.

costs and FTEs, which in turn drives greater BSCs. The need for BSC is therefore linked to overall levels of capex, and FTEs. It is wrong to assume that BSC cost are any more predictable than CAIs. In both cases there is uncertainty and given their critical role in delivery, funds need to be available when required. Re-openers, if not automatic, can result in long time lags between an application and a decision on funding. On this basis, a UIOLI mechanism provides a more responsive solution. This would be in the interests of customers as it would allow the necessary investment to support growth delivering both now and, in the future, but at the same time would ensure than any unused funding would be returned to customers. We have already put forward suggestions for how such mechanisms could work and it is outlined further in paragraph 2.9.3 below. We would be keen to work with Ofgem and the other TOs to further develop the details of the preferred mechanism in advance of FD.

4. **Ofgem should publish details on the reporting requirement for this mechanism as early as possible, as well as how any information reported by the TOs will be assessed.** A lack of clarity regarding how the mechanism will operate in practice creates additional uncertainty. It is imperative that the mechanism is simple to use, and the required evidence base is well understood to mitigate the risk of under-recovery.

2.9.3 Taking these points together, we consider that Ofgem should adopt one or a combination of the following mechanisms:

- **A BSC UIOLI linked to the CAI UIOLI allowances.** This could be based on outturn data for 2014-2024 which suggests a ratio of 0.32 i.e. for every pound spent on CAI, the mechanism could allow TOs to spend £0.32 on BSC allowances. This approach would have the advantage of providing an automatic uplift based on the CAI UIOLI but would also ensure funds were returned promptly to consumers if unused. Further detail on this mechanism is set out in NERA's report in Annex 3.1[163].
- **A BSC Re-opener with an automatic trigger based on Baseline BSC exceeding a pre-defined threshold.** This could also have a secondary trigger on Baseline Revenue set at 1% in line with standard materiality threshold in other re-openers. This approach would enable the mechanism to be triggered only when required. It would follow the same assurance requirements as other re-opener submissions.
- **These mechanisms could be combined.** The UIOLI could serve as the lead mechanism to provide certain and timely funding to support step-change in organizational growth and protect customers interests by ensuring the full return of any underspend without being adjusted by the TIM. The re-opener could then be applied in a mechanistic form to address any subsequent investment needs if and when required.

2.9.4 We are keen to work with Ofgem and the other TOs to further develop the details of the mechanism in advance of FD.

[163] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.5.2, p42-43.

COST ASSESSMENT – INDIRECT COSTS (CAI & BSC) QUESTIONS

ETQ 57 What are your views on the proposed blended approach to CAI? Do you agree with the weights applied?
We strongly disagree with the proposed approach. Unchanged the approach will fundamentally compromise our ability to deliver the required investment in RIIO-T3.

Significant changes will be required to address the limitations of the current approach. To the extent that this results in material changes to the treatment of allowances, this may require Ofgem to provide all stakeholders with the opportunity to comment on the impacts through a focused consultation in advance of FD.

Fundamental to our concerns is that we do not consider the outputs of the regression modelling to be credible given it would result in modelled costs significantly below both Ofgem's RIIO-T2 allowances and below our actual and forecast costs for RIIO-T2. This is fundamentally inconsistent with an investment profile to support growth.

Our principal concerns with the modelling are as follows:

- **The inclusion of a statistically insignificant and negative time trend as part of the model specification has no operational rationale.** It results in a £107m reduction in the modelled costs based on the regression and a £51m reduction in our baseline capex allowance after the application of the 50:50 weighting and OE (a 4% p.a. efficiency challenge on top of OE). Removing the time trend results in a minimal reduction in model robustness based on the adjusted R-squared. The time trend must be removed from the CAI model.

- **MEAV is not a proxy for the new investment required in RIIO-T3** – While MEAV has a strong correlation with CAIs on an outturn basis, it has no statistically significant correlation on a forecast basis. Capex and FTEs retain a statistically significant correlation with CAIs when focusing on forecast data, suggesting that these drivers better capture forward-looking cost pressures. Both FTEs and capex should be used and given sufficient weighting the model.

- **The coefficients on MEAV and Capex in the CAI regression imply material diseconomies of scale with respect to CAI costs.** The sum of coefficients on the scale drivers is c. 1.16, suggesting that a 10% increase in 'scale' leads to a c.16% increase in CAI costs. This is inconsistent with the standard economic and operational understanding of these costs since they are expected to benefit from economies of scale.

- **The models are over-fitted as Ofgem's modelled costs are very sensitive to the level of costs for NGET and NGGT.** Statistical analysis undertaken by NERA and provided in Annex 3.1[164] alongside this report shows that Ofgem's models are driven by differences in scale rather than the relationship between indirect costs and cost drivers.

- **The range of RIIO-T3 efficiency scores from Ofgem's regression analysis for RIIO-T3 does not satisfy a common-sense plausibility check.** An efficiency score of 2.91 for us meaning that our forecasts for RIIO-T3 are 2.9 times the modelled costs is unrealistic when compared to 0.51 for NGET which would mean Ofgem's modelled costs for NGET are twice their forecast costs. The equivalent range in RIIO-ED2 FD was circa 22%. It is worth noting that we rank first on an out-turn basis with an efficiency score of 95%, but last on the forward position with a score of 291%, while NGET is estimated at 51%. This is because the baseline drivers do not account for the step-change in growth that is required for SPT. Ofgem's own forward-looking ratio

[164] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.2.5, p17-19.

benchmarking for our results in much more plausible modelled costs. The resulting RIIO-T3 efficiency score for the Best View forecast is 1.09. The modelling must be revisited to achieve a more plausible range of efficiency scores.

- **Different modelled methods must provide a consistent view of costs for the methods to be robust**. We agree with the principle of using multiple methods to inform cost assessment but note that there are material inconsistencies in the modelled costs for CAI between the econometric benchmarking (based on historical actuals) and the more forward-looking ratio analysis. The ratio analyses provide modelled costs three times higher than those under the econometric benchmarking and significantly closer to our proposal. On this basis, we conclude that the econometric benchmarking set out in DD does not sufficiently account for our future operating circumstances and is subsequently not robust.

- **The 50:50 weighting Ofgem has applied to the regression analysis and the forward-looking ratio analysis is not appropriately justified**. Ofgem argues that this is to keep a balance between the two types of analysis. In practice it is clear that the future will be distinctly different than the historical period used for the regressions which had a relatively stable level of activity with slow growth. Figure 2-2 clearly demonstrates the rapid growth in our connections enquires which is driving a significant increase in the need for indirect activities.

  The choice of the 50:50 weighting therefore seriously disadvantages the Scottish TOs which have a significantly greater requirement for growth going into RIIO-T3. We note that increasing the weight on econometric benchmarking by 5% results in a circa £18m reduction in our modelled CAI allowance (and vice versa). Since minor adjustments to the weights result in a material impact on our baseline allowance for CAI we can only conclude that the econometric benchmarking is not robust at DD.

Alternatives for determining CAI allowances

Notwithstanding these concerns we are focused on putting forward constructive alternatives which will help to make the existing analysis more robust. We consider that there are three alternative approaches that can be used for reaching sound and well justified allowances from the CAI benchmarking:

- **Preferred Approach 1: Forward-looking Best-View Regression Analysis.** This entails using appropriate, forward-looking, cost drivers including FTEs and Capex. Ideally, this should be on Best View basis including new information [redacted]. This is our preferred approach. We consider that adopting Best-View is the optimal approach as it addresses the root of the problem i.e. fully reflecting the required CAIs to support growth, rather than trying to mitigate the impact through changes to the modelling.

- **Alternative Approach 2: Apply analysis sequentially.** Ofgem's econometric model (without the time trend and with the period extended to include the forecasts for 2025 and 2026) can be used to derive an efficient cost prediction for 2024–26. This efficient cost prediction could then be rolled forward into RIIO-T3 to account for growth. We further propose this is moderated by a scaling factor of 0.67 (consistent with the average coefficient on FTEs across 6 indirect regressions which include FTEs as a cost driver and in line with the proportion of labour costs within our total indirect costs excluding contractor indirects) to account for there not being a 1 to 1 relationship between FTEs and indirect costs.

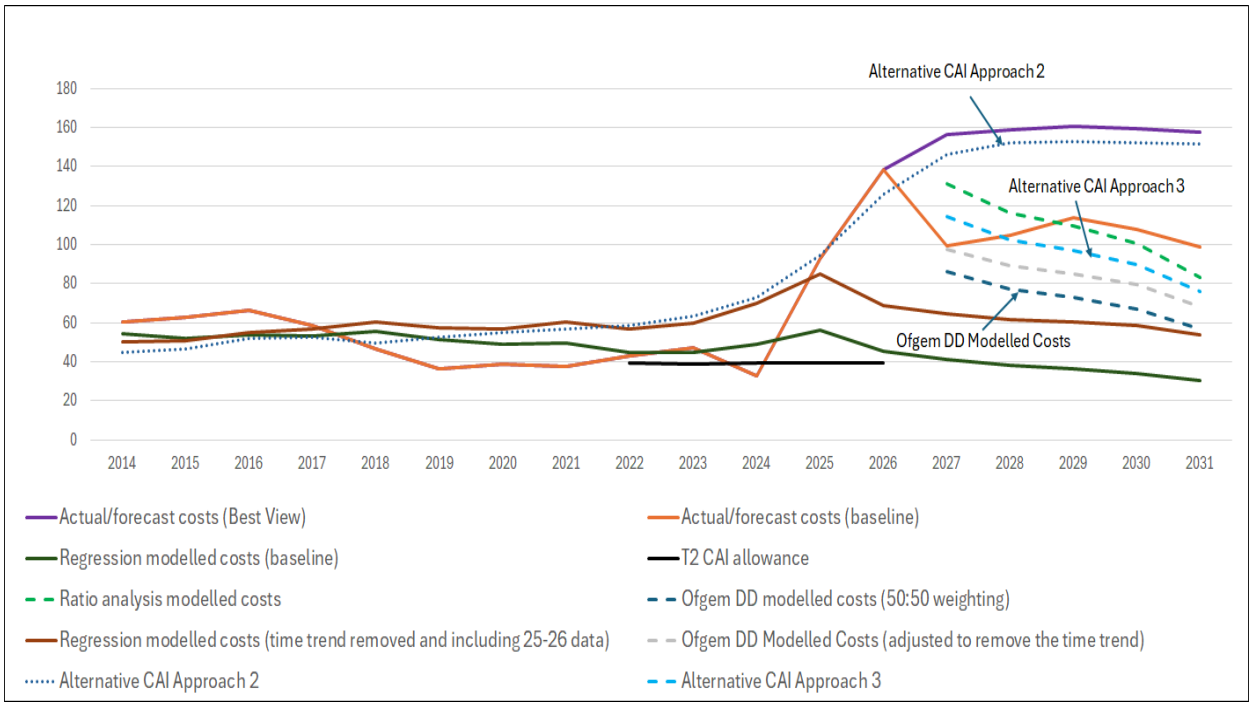
- **Alternative Approach 3: Remove the time trend, extend the regression to include the 2025 and 2026 forecasts, and increase the weight on ratio benchmarking.** This is a simpler approach based in increasing the weight on the forward-looking analysis to better reflect the step-increase in growth for the Scottish TOs in RIIO-T3 and the associated requirement for indirects. For example, we have modelled the impact of applying a 75% weighting to the ratio

benchmarking with a 25% weighting applied to the regression modelled costs excluding the time trend.

The figure below shows the impact of two of these proposed alternatives for CAI. The dark blue dotted line shows the modelled costs for **Alternative Approach 2**. The light blue dashed line shows the modelled costs for **Alternative Approach 3**. **Preferred Approach 1** is not reflected in the chart as we do not have the relevant information [redacted] at this stage to be able to model this.

[redacted]

Figure 2-8 - Impact of alternative approaches for estimating CAI modelled costs for RIIO-T3[165]



Approach 1 is our preferred solution on the basis that Best View analysis will provide the most robust outcomes. In the absence of Best View information, **Alternative Approaches 2 and 3** provide pragmatic solutions to addressing the flaws that we have demonstrated exist in DD.

Each alternative would represent a substantial improvement and thereby enable CAI allowances more aligned with the demonstrated investment requirements in RIIO-T3.

ETQ 58 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?

In principle, we welcome the inclusion of a separate UIOLI mechanism for additional CAI costs beyond the baseline. However, we have concerns about how the value of the UIOLI pot has been calculated and ultimately whether it will enable the investment required to support our anticipated growth in RIIO-T3.

We consider the solution lies within the scope of what Ofgem has proposed by determining more appropriate parameters and that ultimately this will be in the interests of GB consumers. Six changes are required to enable this mechanism to work more effectively and deliver the required growth:

1. **The ratio used to calculate CAI UIOLI for relevant projects should be raised from 10% to c. 15%** - This would remain a conservative parameter but would be based on evidence from a

[165] Figure 2-8 is the same as Figure 2-5, and has been included again for ease of reference

combination of more robust analytical approaches including the coefficient on capex in the historical CAI regression, the RIIO-T2 opex escalator and a modelled CAI-to-capex ratio.

2. **The £25m threshold for capex project should be removed** – This reflects the fact that CAI resources are required for all projects, and their requirement is not a direct reflection of materiality but rather will vary by complexity. We present evidence in Table 2-5 of the material impact this has on us – only 30% of projects would fall within the thresholds proposed for the mechanism. This demonstrates the application of an arbitrary cap has no correlation with the need for CAIs and the reason it should be removed.

3. **The £150m threshold for determining the scope of the allowance should be reviewed with exclusions only required for mechanisms with bespoke CAI funding** – It must align with other relevant thresholds such as those for ASTI and CSNP projects in order to 'right-size' the resources to deliver the required investment. The only exclusions should be for mechanisms with bespoke CAI funding.

4. **The mechanism should recognise where projects span price control periods** – In reality there will be overlap between price control periods, the mechanism should allow the required CAI resource to be accessed when required. This will be critical to timely delivery. The reporting arrangements can easily be adjusted to ensure the timing of investment is fully reflected and avoid double funding.

5. **A mechanism should be introduced that enables additional indirects funding where the full CAI UIOLI has been utilised** – To ensure timely investment this mechanism should be mechanistic, available from the start of RIIO-T3 and be automatically triggered when the UIOLI pot reaches a designated level rather than relying on an additional process which would introduce unnecessary complexity and uncertainty. The mechanism should be fully realised in FD and embedded in the licence drafting.

6. **Clarity should be provided on reporting requirements and how information will be assessed** – It is imperative that the mechanism is simple to use, and the required evidence base well understood to mitigate the risk of under-recovery.

Taken together, all these measures would provide the most efficient outcome for consumers by ensuring funding is only provided when required but also enabling timely investment to drive growth which will ultimately bring down bills and improve longer-term energy security.

ETQ 60 Do you agree with our approach to BSC? How do you think this could be improved?

We strongly disagree with the proposed approach to BSC funding. Unchanged the approach will fundamentally compromise our ability to deliver the required investment in RIIO-T3.

We note that six BSC models were trialled, of which one final model was selected at the DD. Ofgem's selected regression (Model One) is a historical regression over the period 2014 to 2024 and uses a composite scale variable (CSV) which combines FTEs, Capex and MEAV into a single cost driver. The output of this regression is not credible as modelled costs are significantly below the RIIO-T2 actual and forecast costs.

Our principal concerns with the modelling are as follows:

1. **The decision to select Model One alone is not supported by the statistical results from the BSC regression.** Model One does not have the highest model fit, fails the RESET test (at the 10% level)[166], fails the heteroskedasticity test at the 5% significant level, and leads to the highest

[166] This is discussed in further detail in NERA report (Section 3.2.3) which is provided in Annex 3.1.

range of estimated efficiency scores in ET3. As highlighted above and in Table 2-6, Model One is not clearly superior to the other models. A strong a case can be made from a statistical perspective for models Four to Six. On this basis, the modelled costs estimated for RIIO-T3 under the regression analysis should be an average of the results of Models One, Four, Five and Six.

2. **MEAV is given too high a weighting the in analysis.** The CSV assigns a very high weighting (79.5%) to MEAV which does not vary significantly over time relative to the other drivers (FTEs, Totex), so it cannot account for forward-looking cost pressures. Ofgem's modelling shows that the coefficient on FTEs is at least as high as the coefficient on MEAV when they are included as separate drivers, yet it received 8 times less weight in the CSV. If the CSV is to remain in the models, the weight on MEAV should reduce from 79.5% to 35.4%, while the weight on FTE increases from 11.5% to 55.6%. This would allow for the model to better account for the step-increase in growth.

3. **There is a lack of transparency on how Ofgem has used regression analysis to estimate baseline FTEs from the Best View forecasts using capex as a cost driver.** There is no information on the model specification used, the input data and the statistical results. Ofgem has then used the output of the FTE regression as an input to the regression modelling RIIO-T3 BSCs. We consider a more robust approach would be to obtain forecast baseline FTEs from each of the TOs, so we therefore welcome Ofgem requesting this information.

4. **Different modelled methods must provide a consistent view of costs for the methods to be robust.** As discussed above for CAI, we agree with the principle of using multiple methods to inform cost assessment. However, they should provide a consistent view of costs for the methods to be robust. We note that there are material inconsistencies in the modelled costs for BSC between the econometric benchmarking which is based on historical actuals and the more forward-looking trend analysis. The modelled costs from the forward-looking trend analysis are 2.7 times higher than the modelled costs under the econometric benchmarking. With the trend analysis providing modelled costs closer to our proposal, we consider the econometric benchmarking does not sufficiently account for our future operating circumstances and is subsequently not robust.

5. **The 50:50 weighting Ofgem has applied to the regression analysis and the forward-looking ratio analysis is not appropriately justified.** Ofgem argues that this is to keep a balance between the two types of analysis. However, this choice seriously disadvantages the Scottish TOs which have significantly more growth going into RIIO-T3. For BSC, a 5% increase in weight results in a circa £8m reduction in allowances and vice-versa. Since minor adjustments to the weights result in a material impact on allowances, we consider the econometric benchmarking to not be robust in DD.

6. **Ofgem's proposed allowances are very sensitive to a number of the assumptions made.** Changing the starting point for growth in Ofgem trend analysis from 2026 to the other option it has considered, 2024, would increase Ofgem's modelled costs by £66m.

Alternatives for BSC

We consider that there are three good alternatives for reaching well justified allowances from the BSC.

- **Preferred Approach 1: Forward-looking Best-View Regression Analysis.** This entails using appropriate, forward-looking, cost drivers including FTEs and Capex. Ideally, this should be on Best View basis including new information [redacted]. We consider that

adopting Best-View is the optimal approach as it addresses the root of the problem i.e. fully reflecting the required BSCs to support growth, rather than trying to mitigate the impact through changes to the modelling.

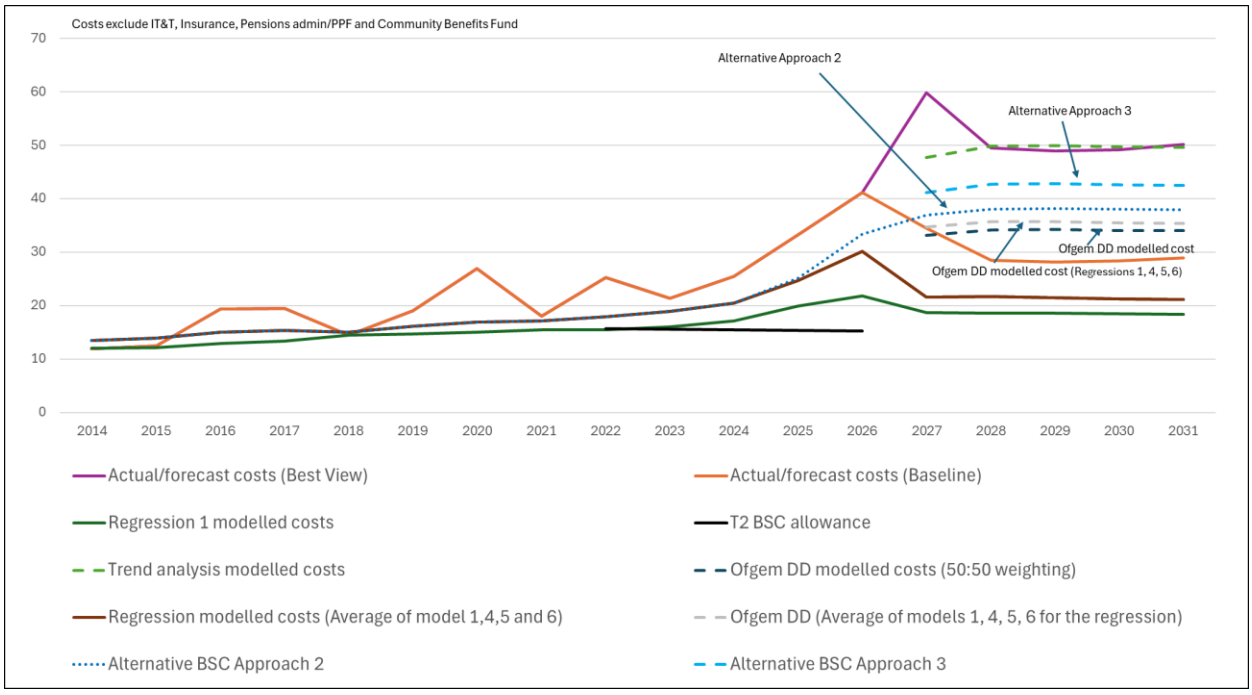
- **Alternative Approach 2: Sequential application of methods.** A triangulation of Models One, Four, Five, and Six can be used to derive efficient modelled costs in RIIO-T2 (2024 to 2026 reflecting the fact that a large proportion of the planned growth in FTEs and indirects needs to happen in the last two years of RIIO-T2). Ofgem could then roll the average 2024-26 efficient modelled cost forwards to take account of growth. For example, by adjusting for the percentage change in FTEs between 2024 and 2025, 2026 and 2027 etc moderated by a scaling factor of 0.67 based on the same rationale outlined for CAIs.

- **Alternative Approach 3: Increase the weighting on the forward-looking ratio benchmarking for both the Scottish TOs.** Based on the need for substantial network expansion for the Scottish TOs and the resulting requirement for growth in indirects, increasing the weighting on the forward-looking trend analysis for both the Scottish TOs to 75%, with a 25% weighting would be applied to the average modelled costs from Models 1, 4, 5 and 6.

Figure 2-9 below shows the impact of two of the proposed alternatives for BSC. The dark blue dotted line shows the modelled costs for **Alternative Approach 2**. The light blue dashed line shows the modelled costs for **Alternative Approach 3**. **Preferred Approach 1** is not reflected in the chart as we do not have the relevant information [redacted] at this stage.

[redacted]

Figure 2-9 - Impact of proposed BSC alternatives for estimating modelled costs for RIIO-T3[167]



As noted, **Preferred Approach 1** is our preferred solution on the basis that Best View analysis will provide the most robust outcomes. In the absence of Best View information, we consider **Alternative Approaches 2 and 3** provide pragmatic solutions to address the flaws in the proposed approach that we have demonstrated exist in DD.

[167] Figure 2-9 is the same as Figure 2-7, and has been included again for ease of reference.

Each would represent a substantial improvement and thereby enable BSC allowances more aligned with the demonstrated investment requirements in RIIO-T3.

ETQ 61 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?

The proposed RIIO-T3 reopener mechanism does not currently provide appropriate protection for us for a material increase in BSC.

We have identified the following four changes to the mechanism which should be made at FD to ensure the mechanism operates effectively for all TOs and in the interests of consumers by providing an appropriate balance of risks:

1. **The application window should be early in RIIO-T3 (Years 1 or 2) or based on an automatic trigger** – BSCs are not a consequence of investment but a critical driver of delivery, especially given BSCs are mostly driven by the required FTEs. The mid-period timing of the reopener outlined in DD would deliver additional funding too late during the price control period as the funding would only feed through in Year 5 of the price control. An automatic trigger would be better as it would recognise that different TOs may require additional BSC at different points in the RIIO-ET3 period.
2. **The reopener threshold should just be based on BSC costs** – The proposed application of a totex threshold (non-variant totex) for the BSC reopener creates an unintended consequence that if a TO achieves significant efficiencies on another area of cost such as non-load related capex or NOCs, the TO may then be unable to trigger the BSC reopener. This effectively undermines the intended purpose of the TIM to drive improvements in efficiency. Based on our calculations, even if SPEN spent in line with its Best View forecast for BSC, it would not be able to trigger the reopener because the value would not reach the much higher totex trigger point.
3. **There should be a BSC UIOLI pot that is trued up as part of the BSC reopener** – While Ofgem has raised concerns about a UIOLI mechanism not being practical for BSC, we do not agree with this conclusion. Higher capex drives a greater requirement for CAI costs and FTEs, which in turn drives greater BSCs. The need for BSC is therefore linked to overall levels of capex, and FTEs. It is wrong to assume that BSC cost are any more predictable than CAIs. In both cases there is uncertainty and given their critical role in delivery, funds need to be available when required. Re-openers, if not automatic, can result in long time lags between an application and a decision on funding. On this basis, a UIOLI mechanism provides a more responsive solution. This would be in the interests of customers as it would allow the necessary investment to support growth delivering both now and, in the future, but at the same time would ensure than any unused funding would be returned to customers. We have already put forward suggestions for how such mechanisms could work and it is outlined further in paragraph 2.9. 3 of this response and repeated below. We would be keen to work with Ofgem and the other TOs to further develop the details of the preferred mechanism in advance of FD.
4. **Ofgem should publish details on the reporting requirement for this mechanism as early as possible, as well as how any information reported by the TOs will be assessed.** A lack of clarity regarding how the mechanism will operate in practice creates additional uncertainty. It is imperative that the mechanism is simple to use, and the required evidence base is well understood to mitigate the risk of under-recovery.

Taking these points together, we consider that Ofgem should adopt one or a combination of the following mechanisms:

- **A BSC UIOLI linked to the CAI UIOLI allowances.** This could be based on outturn data for 2014-2024 which suggests a ratio of 0.32 i.e. for every pound spent on CAI, the mechanism could allow TOs to spend £0.32 on BSC allowances. This approach would have the advance of providing an automatic uplift based on the CAI UIOLI but would also ensure funds were returned promptly to consumers if unused. Further detail on this mechanism is set out in NERA's report in Annex 3.1[168].
- **A BSC Re-opener with an automatic trigger based on Baseline BSC exceeding a pre-defined threshold.** This could also have a secondary trigger on Baseline Revenue set at 1% in line with standard materiality threshold in other re-openers. This approach would enable the mechanism to be triggered only when required. It would follow the same assurance requirements as other re-opener submissions.
- **These mechanisms could be combined.** The UIOLI could serve as the lead mechanism to provide certain and timely funding to support step-change in organizational growth and protect customers interests by ensuring the full return of any underspend without being adjusted by the TIM. The re-opener could then be applied in a mechanistic form to address any subsequent investment needs if and when required.

We are keen to work with Ofgem and the other TOs to further develop the details of the mechanism in advance of FD.

ETQ 62 Do you agree with our approach to MEAV? What do you think we could do to improve its robustness?

While MEAV is a relevant cost driver in the historical analysis there is no good relationship between BSC or CAIs in the forecast data. Therefore, the key step that Ofgem can take to improve the robustness of how it is used in modelling is by placing a greater weight on capex and FTEs as cost drivers to reflect the expected step-increase in growth in RIIO-T3.

Ofgem maintains that testing on MEAV as a lagging measure has only had a marginal impact on model fit. While model fit serves as a useful indicator, it should not be the primary criterion for model selection. If, as acknowledged by both Ofgem and the TOs, MEAV is understood to exhibit a lagging nature, any model incorporating it should reflect this characteristic. Failure to do so risks producing a biased estimate for the effect of MEAV on CAI or BSC, potentially resulting in inaccurate cost allowances for the TOs which fail to recognise the indirects needed to enable the required growth in investment.

We consider the coefficient on MEAV is disproportionately high, given that this captures general scale and not the level of activity. Given CAIs will primarily be driven by the scale of the investment programme, then this would imply a higher coefficient on CAPEX and on FTEs would provide more meaningful results.

[168] NERA (2025), 'Review of Ofgem's RIIO-ET3 Draft Determination on Opex and Risk & Contingency: Prepared for Scottish Power Transmission,' August, Section 3.5.2, p42-43.

Chapter 3 - Cost Assessment – Key Totex

3.1 Load and Non-Load

3.1.1 Ofgem has adopted a needs case assessment for load and non-load related capex, followed by unit cost benchmarking and engineering reviews. We are facing a gap of £45m in Capex-related costs, equivalent to approximately 8.5% of its total submitted allowances. The majority of this gap is attributable to non-load related capex, which accounts for £39m of the total difference, while load-related capex contributes £6m. However, in relative terms, the variance between submitted and modelled costs for load-related capex represents a 16% gap, compared to 8% for non-load related capex.

3.1.2 Overall, we consider that Ofgem has made positive progress in its load and non-load related capex assessment for RIIO-T3 having made important refinements to the analytical framework used in RIIO-ET2, placing more weight on engineering justification and optioneering and applying a more holistic approach to unit cost benchmarking. However, there remain several areas of concerns which we consider result in inappropriate adjustments to our forecast costs. These include:

1. **An over-reliance on ET2 data despite the unprecedented investment challenge recognised by Ofgem for RIIO-T3 –** Even though the benchmarks can no longer be based solely on RIIO-ET2 data, using the full time series means that changes in our unique operating circumstances between regulatory periods will still be overlooked for assets that are assessed under unit cost benchmarking.
2. **The enduring lack of clarity on how some aspects of the engineering assessment impact decision making -** It is imperative that the expert assessment should be performed on a consistent, transparent, structured and evidence-based manner across TOs. However, equally we do recognise that Ofgem has taken a number of steps to seek to improve the transparency of this process and which is welcomed.
3. **Setting Risk & Contingency Allowances at 5% of the scheme direct capex is prohibitively low. -** As part of our Business Plan submission, we presented third party analysis in our Cost Assessment and Benchmarking Approach Annex based on a much larger sample of schemes evidencing the R&C allowances we are requesting. There is no evidence that this information has been taken into consideration and the 5% proposed appears to be an entirely arbitrary figure. It is important that this analysis is undertaken by Ofgem on a robust basis to ensure that sufficient allowances are provided both as part of the baseline and in future uncertainty mechanisms.

Ofgem's project assessment model (PAM)

3.1.3 The PAM is a broad-based approach to benchmarking the costs of projects; it deploys a toolkit, drawing upon a range of quantitative and qualitative sources. It includes the use of unit cost benchmarks, engineering and needs case expert reviews.

3.1.4 While we retain reservations with the application of the PAM, we recognise that Ofgem has taken positive action to evolve the models in order to address previous weaknesses. In particular, we welcome the steps taken to simplify the models and to engage with TOs to improve understanding. Further, we welcome the use of the PAM to combine engineering views with the assessment of unit costs and risks. This provides a more solid foundation for setting allowances [169] At the DDs, the PAM assessed submitted costs for non-load capex at the individual scheme level, which is less granular than its assessment at ET2 which was set at the asset level.

3.1.5 We also recognise and welcome the evolution of the engineering review in RIIO-T3 to place more focus on the needs case and optioneering. This is important to ensure that licensees bring forward the necessary investments which are developed to a level of maturity and presented with

[169] SPEN (2024), 'Cost Assessment and Benchmarking Approach (including RPEs & OE)', December, p.13.

sufficient transparency. However, it is also imperative that this is supplemented by information from TOs' cost books such as our Manual of Standard Costs to ensure that the costs are efficient.

3.1.6 To maximise the value of PAM, we consider that the following changes should be made to it at FD:

1. The PAM should be restricted to areas where there is robust data that should also be adjusted for recent extreme price volatility;
2. Benchmarks should be robust and not affected by cost allocation differences and partial capture of costs; and
3. Any assessment by PAM should ensure that an efficient company would be able to fully recover.

Engineering justification

3.1.7 We welcome Ofgem's view of our engineering justifications (EJPs), i.e. "SPT's EJPs are all of a similar high quality and clarity. The supporting information provided is clear and the data consistent with the proposed investments. SPT's approach to optioneering is clear and appears standardised." We have a strong track record in high quality, fully transparent submissions and Ofgem's assessments are noted. Elsewhere in this response, we comment on some elements of Ofgem's approach but we also recognise that Ofgem's engineering assessment has not altered the DD totex position.

3.1.8 We are concerned at Ofgem's finding that "In some cases, SPT's justification for this [the use of GIS solution] has not been sufficiently robust or evidenced at this stage." We note in our response to SPTQ8 that of the schemes Ofgem has identified, in only one case have we proposed a GIS solution following an extensive optioneering exercise. Please refer to that response for more detail. However, Ofgem has not provided sufficient detail on what they consider to be lacking to allow us to respond.

Unit cost benchmarking

3.1.9 While we welcome Ofgem rolling up unit cost benchmarks and applying adjustments at a more holistic scheme level, there is still an issue of bias and the risk of 'cherry picking' in Ofgem's approach to unit cost benchmarking. We welcome Ofgem's recognition of the existence of structural breaks across periods and that it has accordingly avoided selecting the lowest benchmark between RIIO-ET2 and RIIO-ET3 for Load and Non-Load related capex (as was the case in ET2). Instead, Ofgem has benchmarked 11% of non-risk costs against ET3 benchmarks, 37% against ET2 and ET3 benchmarks, while 52% were qualitatively assessed.

3.1.10 However, the reliance and influence of RIIO-ET2 data for the unit cost benchmarking exercise remains a concern. The influence of ET2 benchmarks, should forecast ET3 unit costs be higher than ET2, implies that Ofgem considers any increases in unit costs would be deemed as 'inefficiency'. It also implies that Ofgem considers past unit cost trends to be reliable predictors for future unit costs. We have shown, as part of our competitive tendering process, that all our contracted activity is cost efficient. As demonstrated in our Business Plan, approximately 95% of load and non-load related capex has been or will be competitively tendered, and the costs that have not yet been tendered have been estimated using our Manual of Standard Costs (MoSC), which derives costs associated with different assets from previous competitive tenders. Further, we have also commissioned work from independent consultant Arcadis to assess and assure the overall efficiency of our investment programme and carry out benchmarking for samples of load and non-load related projects. As such, any reductions to the allowance due to lower costs in ET2 would result in underfunding for ET3. This could subsequently impact our ability to perform our load and non-load capex activity as planned. Therefore, we recommend using only the ET3 period to estimate the unit cost benchmarks.

3.1.11 Ofgem should consider the use of a 'symmetrical adjustment' to reward ambitious below-benchmark forecasts from TOs. Alternatively, the BPI mechanism should be revised to sufficiently reward below-benchmark unit costs and also penalise above-benchmark unit costs from TOs which would benefit from this 'downwards only' unit cost benchmarking methodology.

Risk and contingency

3.1.12 We are very concerned that the allowance, where risk costs are higher than £100k, has been set at 5% of the scheme direct capex. Certain projects such as Redshaw 400/132kV substation would be inherently riskier due to access across large water mains and proximity to SSSI and SAC sites. The Ground Investigations necessary for design and construction of the access road has been delayed by six months due protracted discussions with Scottish Water to secure consents to cross the water mains. Site drainage could outfall to the protected sites, hence proposed development drainage must take into account all environmental constraints associated with these sites. A uniform ratio across all projects therefore assumes such projects have identical risk profiles, and is not flexible, nor accounts for, the particular risks associated with each scheme. Studies on capital project risk[170] also support a figure materially higher than 5%, with the average project running 37% over budget.[171] As such, many of our projects may be riskier, such that it would require R&C costs to be above the 5% threshold.

3.1.13 Ofgem has not provided any quantitative analysis to demonstrate that 5% is appropriate, nor has it reconciled between this percentage and the 7.5% applied at RIIO-T2. As part of our Business Plan submission, we presented third party analysis by S&C Electric[172] based on a much larger sample of schemes evidencing the R&C allowances we are requesting. This analysis reviewed historical planned and actual released risk and contingency costs for a sample of 33 load-related projects excluding 6 outliers and suggested an unweighted mean planned risk, and contingency of 10.9% for load-related expenditure, whereas the unweighted mean for released costs was 12.9%. Similarly, the analysis of a sample of 30 non-load related projects excluding 1 outlier determined an unweighted mean planned risk, and contingency of 8.9% of the project costs, whereas the average released costs were 9.2%. We note that such findings are not unique to us with SSEN-T indicating an increased construction risk position of [redacted] and NGET stating a risk contingency factor of [redacted] for early phase projects.

3.1.14 There is no evidence that this information has been taken into consideration by Ofgem and the 5% proposed appears to be an arbitrary figure. It is important that this analysis is undertaken by Ofgem on a robust basis to ensure that sufficient allowances are provided. Such a low threshold places unnecessary risk on Capex projects, which may result in delays to investment, or increased vulnerability to cost shocks and unforeseen circumstances that may result in overspend. This is particularly concerning given, as we highlighted in Chapter 1 - Ensuring an Investable Finance Package, we are likely to be exposed to a significantly higher level of risk due to the step-increase in investment required in RIIO-T3. This is another factor that contributes to the view that the current package would fail the "fair bet" assessment.

3.1.15 We note that the extension of ASTI delivery incentives to a broader range of load-related schemes in RIIO-T3, together with the new licence obligations on delivery of such projects will increase the risk borne by the TOs during RIIO-T3 and as such is inconsistent with a 5% allowance for risk and contingency which is a lower value than the 7.5% for RIIO-T2 and the values put forward in the TO forecasts.

3.1.16 Ofgem has noted that it has "found significant variance in the approaches taken by each TO in terms of their costing methodologies, manifesting in a high variance of the requested risk costs.

[170] Capital project risk is typically measured as over-run compared to budgeted cost and planned schedule, though can also encompass conformance to specification.
[171] Asvadurov, S., Brinded, T., Brown, T., Ellis, M., Knox, D., & Speering, R. (2017), 'The art of project leadership: Delivering the world's largest projects', September.
[172] This was embedded in our Business Plan response with more detail submitted as part of the SQ process.

Broadly, we noted very limited justification within EJPs for particularly large risk costs, with minimal justification for the quantum of these costs." Ofgem has presented no analysis supporting this finding of significant variances, while, as noted above, we conducted analysis of sixty-three historical schemes covering both load and non-load-related capex to determine the appropriate R&C percentages to apply. We also provided further analysis to Ofgem in response to its SQ113. From our analysis there are recurring themes of risk events beyond our control that are being captured. There are trade-offs for projects in relation to mitigating risk upfront (e.g. for land conditions how much ground investigation takes place etc) and we must strike a reasonable balance between time, cost and quality.

3.1.17 As noted above, we have provided significant justification through our analysis of 63 historical schemes and additional analysis as part of the SQ. We therefore would expect Ofgem, as a minimum, to show analysis demonstrating why our analysis and justifications inappropriate based on numerical evidence rather than simply stating it is poorly justified (notwithstanding that we consider our analysis and forecasts to be appropriate and adequately justified). This is important to show that it has given appropriate weight to the available evidence.

3.1.18 Ofgem notes that "While the changes to the TIM and newly proposed mechanisms may not directly affect potential R&C costs from arising for individual projects, they are aimed at reducing the risk of the overall project portfolio. Therefore, we did not deem it necessary to provide an R&C allowance based on the TOs' costing approaches." Ofgem has not provided any quantitative evidence showing the impact of the new mechanisms on R&C costs. The TIM is a mechanism that is aimed at incentivising efficiency and addressing additional risks outside the control of TOs. It is not there to correct for flaws in Ofgem's allowance setting at a price control. We can therefore only conclude that the 5% Ofgem has specified is arbitrary and thereby imposes another unjustified efficiency challenge on us and the other TOs.

3.1.19 The 5% ratio should not form the basis for future R&C allowances for capex projects that are funded through Ofgem's Uncertainty Mechanisms given the lack of any substantive basis for this proposed ratio.

3.1.20 We further note as part of the last Cost Assessment Working Group Ofgem raised an alternative view on the treatment of R&C costs. We have significant concerns with this proposal which has not formed part of the DD consultation. Given the late stage at which this was raised and its likely material impact, we would expect the opportunity to formally comment on that proposal if Ofgem intended it to form part of the FD.

3.2 Network Operating Costs (NOCs)

3.2.1 Ofgem has underfunded our Network Operating Costs (NOCs) proposal by circa £77m (excluding OE)[173] at the DD, which results in a gap of circa 22%. The majority of this gap (circa £61m) is driven by the reduction in the Operational Technology allowance. Our response on this is covered in IT&T Chapter **Error! Reference source not found.**.

3.2.2 The remaining gap is a result of two flawed cost assessment methodologies which fail to account for qualitative justifications for the submitted costs. The cumulative effect of the Unit Cost and Annual Average Cost assessment approaches is to render undeliverable some programmes which are critical to network resilience, staff and public safety.

3.2.3 Ofgem's assessment fails to properly award efficient NOCs costs due to:

1. The flawed Unit Cost approach which wrongly assumes that unit costs will only decrease over time and that any increases are automatically inefficient.

[173] The total gap including OE is c. £90m.

2. The Annual Average Cost approach unfairly further reduces modelled unit costs which are themselves artificially suppressed.
3. The absence of any qualitative review of justifications for unit or total cost increases for costs which are quantitively assessed.
4. Failure to test the reasonableness of the models' outcomes to prevent the award of allowances which result in critical programmes being undeliverable.

Unit cost benchmarking

3.2.4 Ofgem's approach will tend to set NOCs allowances below the TOs' efficient costs. Ofgem has relied on a unit cost assessment of each TO's costs to estimate the efficient level of expenditure over the RIIO-T3 control period, unless its materiality thresholds are met for the annual average cost approach to be used. Under the unit cost assessment approach, for areas of activity where companies forecast their unit costs will fall, Ofgem's approach will set lower allowed unit costs than achieved during RIIO-T2, reflecting TOs' expected reduction in unit costs in the RIIO-T3 period. However, where the TOs have forecast rising unit costs, the unit costs allowed by Ofgem will be capped by the unit costs achieved during RIIO-T2, unless the unit cost increase surpasses Ofgem's materiality threshold for the annual average approach. This approach does not recognise that unit costs may still materially and justifiably increase from RIIO-T2 to RIIO-T3 without meeting Ofgem's thresholds.

3.2.5 By relying on the unit cost approach to set NOCs allowances (unless variations meet Ofgem's materiality thresholds), Ofgem is therefore making two assumptions: (1) that TOs' unit costs should be strictly decreasing over time and that any increase should be deemed "inefficient", and (2) that historical and forecast costs are comparable and that past trends are a reliable indicator of future unit cost trends.

3.2.6 Even if there were a tendency for unit costs to fall over time (in real terms, at least) due to the effects of technological progress and improvements in working practices (which is, in fact, already accounted for by Ofgem in their application of OE to NOCs costs) some unit costs will still rise over time.

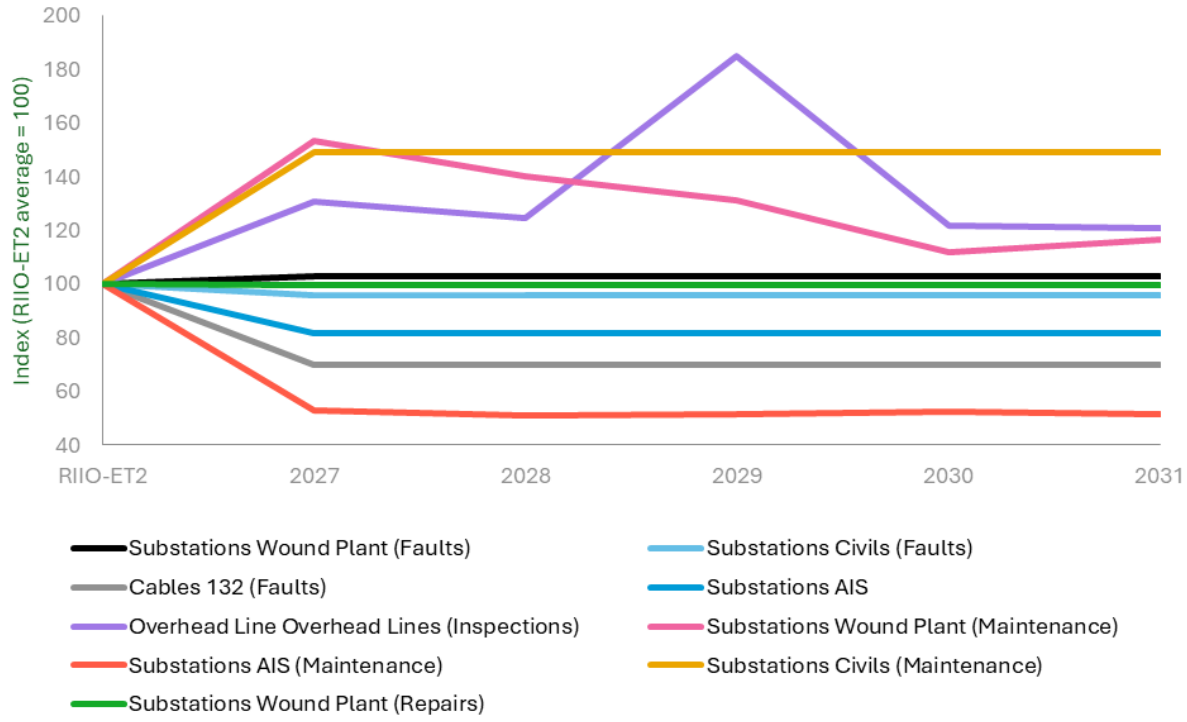
3.2.7 If unit costs do vary over time – both upwards and downwards – for reasons beyond TOs' control and unrelated to efficiency, Ofgem's approach will systematically disallow increases in efficient costs, while setting allowances that reflect reductions in unit costs. The mechanism Ofgem proposes to do this, i.e. crudely taking the minimum of the unit cost achieved in RIIO-T2 and forecast for RIIO-T3, is entirely mechanistic and fails to analyse the reasons for changes in unit costs over time.

3.2.8 We have shown that this assumption is not justified in other cost areas as well, such as, in the assessment of indirect costs, where the use of regression analysis based on historical costs produces modelled allowances significantly lower than Ofgem's own forward-looking analysis and costs for the RIIO-T2 period.

3.2.9 Changes in our unique operating circumstances from regulatory standards (quality, environmental, legal etc.) to changing relationships between unit cost and scale (including our step-increase in growth to deliver the anticipated capex programme for RIIO-ET3) will therefore lead to material changes in our cost environment. This means that historical unit costs are no longer a reliable indicator of future unit costs for NOCs.

3.2.10 The following figure shows the evolution of unit costs of our major NOC activities, sourced from our Business Plan submission.

Figure 3-1 - RIIO-T3 unit costs of major NOCs cost categories relative to T2



3.2.11 As depicted, the unit costs for the majority of our NOC activities are forecast to decline, showcasing our commitment and efforts to unlock efficiencies and deliver for our customers. For example, in the case of fault, repair and maintenance costs, efficiencies have been achieved as we have replaced oil and air blast circuit breakers with equipment that is significantly less complex and cheaper to maintain.

3.2.12 However, we are forecasting an increase in unit costs for some activities for reasons beyond our control. Although the exact cost pressure differs by asset, it is primarily driven by increases in the competitive market price of our procured activities, the increased complexity of our network and factors such as climate change leading extending the growing season for vegetation management. While Real Price Effects (RPEs) may pick up a proportion of the input price pressures faced by suppliers which are passed through to TOs, given the excess demand for certain inputs to meet net zero requirements,[174] such suppliers are to an extent, price-makers. As such, any increases in unit costs outside of input price pressures would be passed onto TOs.

3.2.13 As mentioned, much of our activity is competitively tendered through our market testing process to ensure our unit costs are efficient. As outlined in our Business Plan, over 56% of our RIIO-T3 NOCs have been or will be competitively tendered (with the balance being delivered by in-house resources). The costs associated with vegetation management, service agreements and Operational Technology were all market tested.

3.2.14 SP Energy Networks, as part of the Iberdrola Group, operates under a global procurement model. Our contracting strategy has been developed to further improve resilience and long-term certainty with our supply chain partners. The contract governance process is described in our Workforce & Supply Chain Resilience Strategy and sets out our approach to securing suppliers.[175] Our tender process has been designed to ensure the best outcomes for consumers by balancing the need to deliver efficient outcomes whilst ensuring suppliers can provide the products and/or services to successfully deliver projects. Suppliers will respond to our Invitations to Tender and

[174] Dempsey, H. (2024), 'World's largest transformer maker warns of supply crunch', *Financial Times,* 2 November, last accessed 23 July 2025.
[175] Workforce & Supply Chain Resilience Strategy, Figure 16 page 48.

submissions will be subject to Technical and Commercial assessment. The first stage – which is a question-and-answer process – seeks to determine whether suppliers are able to satisfy our technical specifications (quality), programme requirements (timeliness) and safety performance. The outcome of technical evaluation determines the suppliers that will move to the Commercial assessment phase. Those suppliers will be then subject to multiple rounds of commercial offers, which create competitive tension, and culminate in a final Best and Final Offer (BAFO) submission. The supplier providing the most economic offer will be awarded the contract.

3.2.15 Therefore, if Ofgem does not consider that unit costs could increase (as well as decrease) over time, then any justified increases to our efficient unit costs for certain NOC activities would not be funded. This may subsequently risk our ability to deliver all of the proposed activity. In essence, this approach results in a negative 'ratchet' effect, causing a downward-only bias to allowances. We also consider it to be unjustifiable that one TO could have its RIIO-T2 unit cost applied, while another could be allowed its RIIO-T3 forecast for the same activity. Since many of our activities are tendered to third-party contractors, TOs are essentially price takers with regards to NOC activities. It is therefore feasible, due to differences in the market structure of providers (i.e. changes to competition in the local contractors' market), that one TO may benefit from greater supply-side competition and subsequently lower unit costs, while another may face the opposite circumstances. Since our unit costs are also market tested, and built up from a bottom-up view, in the absence of any evidence of inefficiency, our RIIO-T3 unit costs, and subsequently our proposed allowances, should be allowed in full. Finally, Ofgem has stated in its assessment of Load and Non-load related Capex, that "[Ofgem] considered it important to account for potential high volatility across periods… using ET3 data only where there were concerns that there has been a structural break across periods"[176], indicating that Ofgem acknowledges the cost environment could be different in ET3, and that this would have to be accounted for. However, Ofgem has failed to apply the same logic to NOCs, resulting in an unexplained inconsistency. In fact, for some NOCs assets, our ET3 unit costs are nine to ten times higher than those in ET2, whereas most CAPEX-related assets do not exhibit such a step increase between periods.[177] As per the RIIO-T2 FD, we consider Ofgem should allow qualitative and engineering evidence (as it did at RIIO-T2) to be used where our unit costs are expected to increase in RIIO-T3, in cases where the higher unit costs are demonstrated to be driven by step-changes in our operating environment.[178]

Annual average costs

3.2.16 In contrast to the unit cost approach, the annual average assessment approach allows Ofgem's modelling to acknowledge that costs can increase over time for reasons other than inefficiency. Under this approach, Ofgem divides the total cost for both RIIO-T2 and RIIO-T3 by the number of years over the two control periods (10 years) and sets this annual average cost for each year of RIIO-T3. Therefore, the allowed unit cost for RIIO-T3 will be informed by both the RIIO-T2 unit costs and the increased RIIO-T3 unit costs. Whilst this approach goes some way to acknowledging that unit costs may increase for exogenous reasons (i.e. other than inefficiency), it still uses the RIIO-T2 unit costs to inform the RIIO-T3 allowed unit cost, despite the potential presence of these exogenous factors. However, whilst the annual average assessment approach is an improvement on Ofgem's RIIO-T2 approach, it still cannot distinguish inefficiency from other cost pressures, so is likely to lead to highly misleading results. Additionally, calculating the annual average cost in this way fails to account for changes in workload from RIIO-T2 to RIIO-T3. A possible remedy to the flaw in Ofgem's annual average cost calculation is to normalise the total

[176] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.127.
[177] According to Ofgem's modelling files, our BPDT unit cost for 'OHL 400', after normalisations and the Engineering Review, is projected to be 9.4 times higher in ET3, and 10.5 times higher for 'Cables 275', both within the 'Faults' cost category.
[178] Ofgem (2021), 'RIIO-2 FD – SPT Annex (REVISED)', February, paras 3.49–3.50.

cost of RIIO-T2 by applying a scalar equal to the ratio of RIIO-T3 workload to RIIO-T2 workload before taking the average.

Thresholds for applying annual average unit costs

3.2.17 For certain asset categories, the modelled costs from the unit cost benchmarking were significantly below submitted costs. Ofgem suggests this may be due to historical costs not being a good indicator of ET3 costs.[179] For such categories, Ofgem applies an annual average cost approach should any TO's submitted costs deviate from the TO-specific unit cost approach by 25% and £1m. However, Ofgem fails to sufficiently explain this choice of threshold. It states that the aforementioned threshold results in modelled costs in the middle of a range of trialled combinations from 15% to 30% and from £0.5m to £2.0m.

3.2.18 Given the threshold applied is in the middle of this range of combinations, it is no surprise that modelled costs are also in the middle of its range. Ofgem has not provided any economic, engineering or scientific evidence to support such an arbitrary threshold.

3.2.19 Furthermore, Ofgem combines the percentage threshold (25%) with a monetary threshold (£1m) to limit the number of cost categories moving to an annual average cost approach, Specifically, Ofgem states that over half of assets would be moved to an average cost approach without the monetary threshold, which is triggered when any TO's RIIO-ET3 unit cost is 25% or more higher than its RIIO-ET2 unit cost.

3.2.20 While it is reasonable for Ofgem to combine a percentage threshold with a monetary threshold, and to apply the annual average cost approach to all TOs to not disadvantage a TO with comparable historical and forecast unit costs, we consider such a requirement is a consequence of Ofgem's TO-specific unit cost benchmarking failing to sufficiently account for companies' changing operating circumstances in RIIO-ET3, specifically the Scottish TOs' step-increase in growth to meet their anticipated capex programme.

3.2.21 In essence, there may be cases where a material change (>25%) in unit cost between two periods is required and justified. This can be driven by changing relationships over, time, increasing cost pressures unaccounted for by RPEs, as well as changes to the market for third party contractors undertaking activity on behalf of TOs. As such, qualitative evidence should be considered in such cases where a material increase in unit cost may be expected. For example, we provided justification for increases in some costs on account of information from contractual negotiations (vegetation management) or based on actual costs (substation electricity). It is not evident that Ofgem has considered the evidence justifications submitted with the business plan and has not explained why they have not. As such, Ofgem should consider the operational and engineering evidence outlined in our business plan submission, particularly in cases where we anticipate a material increase in unit costs. We have no evidence that Ofgem has fully considered this information as it has not provided any reasons or justification for rejecting or failing to consider that evidence.

[179] Ofgem (2025), 'RIIO-3 DD – Electricity Transmission', July, p.139.

COST ASSESSMENT – KEY TOTEX QUESTIONS

OVQ 7 Do you agree with our proposal for the physical security PCD?
Safety is our number one priority and physical security of our sites is critical. The approach is as anticipated.

OVQ 17 Do you agree with our design proposal for the resilience re-opener?
The circumstances and route to an authority trigger need to be clearly defined. We re-iterate our previous comments on the SSMC and SSMD that Ofgem is once again failing to acknowledge the requirement to undertake physical security works at sites which do not have a CNI designation. Currently, Ofgem has directed that activities associated with such sites are to be considered as non-load investment and will not be considered under the resilience re-opener. However, the proposed Non-Load re-opener does not permit the inclusion of non-CNI security works. This is a clear gap in the price control framework that the current re-opener package does not allow for changes in the security environment during the price control, our request to Ofgem is that this is addressed in the scope of either the Non-Load or Resilience re-openers.

ETQ 46 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 support the approach in principle of using for a combination of unit cost benchmarking and engineering review. This has been tried and tested in previous controls and represents a sensible approach to the assessment.

An important consideration is then how each of these elements is ultimately used to determine the suitability of costs. While we recognise that Ofgem has taken steps to improve transparency, which are welcome, we retain two main concerns:

(1) The over-reliance on ET2 data despite the separate recognition of the unprecedented investment challenge recognised by Ofgem for ET3. We have shown, as part of our competitive tendering process, that all our contracted activity is cost efficient. As such, any reductions to the allowance due to lower costs in ET2 would result in underfunding for ET3. This could subsequently impact our ability to perform our load and non-load capex activity as planned. This is further discussed in ETQ47.
(2) The enduring lack of clarity on how some aspect of the engineering assessment impact decision making. It is imperative that the expert assessment should be performed on a consistent, transparent, structured and evidence-based manner across TOs.

ETQ 47 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?
While we welcome Ofgem rolling up unit cost benchmarks and applying adjustments at a more holistic scheme level, there is still an issue of bias and the risk of 'cherry picking' in Ofgem's approach to the unit cost benchmarking. We welcome Ofgem's recognition of the existence of structural breaks across periods and that it has accordingly avoided selecting the lowest benchmark between RIIO-ET2 and RIIO-ET3 for Load and Non-Load related capex (as was the case in ET2).

However, the reliance and influence of RIIO-ET2 data for the unit cost benchmarking exercise remains a concern. The influence of ET2 benchmarks, should forecast ET3 unit costs be higher than ET2, implies that Ofgem considers any increases in unit costs would be deemed as 'inefficiency'. It also implies that Ofgem considers past unit cost trends to be reliable predictors for future unit costs. We have shown, as part of our competitive tendering process, that all our contracted activity is cost efficient. As such, any reductions to the allowance due to lower costs in ET2 would result in underfunding for ET3. This is likely to impact our ability to perform our load and non-load capex activity as planned. Therefore, it would be more reasonable to use only the ET3 period to estimate the appropriate unit costs.

Ofgem should consider the use of 'symmetrical adjustment' to reward ambitious below-benchmark forecasts from TOs either directly or by recalibrating the BPI mechanism to sufficiently reward such below-benchmark unit costs.

ETQ 48 Do you agree with our proposal to roll-up unit cost benchmarks and set the benchmarks at the scheme level?

We welcome the proposal to apply a more holistic approach to the benchmarking within the PAM by rolling up the unit cost benchmarking and applying adjustments at a scheme level. However as noted in our response to ETQ47, Ofgem should consider rewarding ambitious below-benchmark bids from TOs.

We have identified that our asset unit costs are approximately £17 million below benchmark levels. Additionally, our Risk & Contingency provisions are reduced by a similar amount. However, these efficiencies in asset unit costs do not appear to be fully reflected within the BPI and may inadvertently increase our exposure to risk.

We respectfully invite Ofgem to re-evaluate this position, considering the level of cost disaggregation and the demonstrated efficiencies. We believe a more balanced approach—either through a reassessment of the BPI or a recalibration of risk exposure—would more accurately reflect our performance.

ETQ 49 Do you agree with our continued use of the PAM? How can this be further improved?

The PAM is a broad-based approach to benchmarking the costs of projects; it deploys a toolkit, drawing upon a range of quantitative and qualitative sources. It includes the use of unit cost benchmarks, engineering and needs case expert reviews.

While we retain reservations with the application of the PAM, we recognise that Ofgem has taken positive action to evolve the model in order to address previous weaknesses. In particular, we welcome the steps taken to simplify the model and to engage with TOs to improve understanding. Further, we welcome the use of PAM to combine engineering views with the assessment of unit costs and risks. This provides a more solid foundation for setting allowances.

With regards to unit cost benchmarks in the PAM, such assessments need to be applied at an appropriate level of granularity to produce cost assessments in a practical, reliable manner. We noted in our BP that 'breaking down projects into extremely granular asset-level costs, benchmarking and reassembling this information is not a robust methodology for providing efficient allowances'.[180] At the DD, the PAM assessed submitted costs for non-load capex at the individual scheme level, which is less granular than its assessment at ET2 which was set at the asset level.

We also recognise and welcome the evolution of the engineering review in RIIO-T3 to place more focus on the needs case and optioneering. This is important to ensure that licensees bring forward the necessary investments which are developed to a level of maturity and presented with sufficient transparency. However, it is also imperative that this be supplemented by information from TOs' cost books such as our Manual of Standard Costs to ensure that the costs are efficient.

To maximise the value of the PAM, we consider that:

- The PAM should be restricted to areas where there is robust data that should also be adjusted for recent extreme price volatility;
- Benchmarks should be robust and not affected by cost allocation differences and partial capture of costs; and
- Any assessment by PAM should ensure that an efficient company would be able to fully recover its project costs.

ETQ 50 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 are very concerned that the proposed allowance where risk costs are higher than £100k, has been set at 5% of the scheme direct capex, which results in a **~£2.2m and ~ £17.7m disallowance** to our load and non-load funding request respectively.

[180] SPEN (2024), 'Cost Assessment and Benchmarking Approach (including RPEs & OE)', December, p.13.

Both the 5% ratio and £100k threshold are arbitrary and lacking in economic or engineering support. Certain projects such as Redshaw 400/132kV substation would be inherently riskier due to access across large water mains and proximity to SSSI and SAC sites. The Ground Investigations necessary for design and construction of the access road has been delayed by six months due protracted discussions with Scottish Water to secure consents to cross the water mains. A uniform ratio across all projects assumes such projects have identical risk profiles, and is not flexible, nor accounts for, the particular risks associated with each scheme. Studies on capital project risk[181] also support a figure materially higher than 5%, with the average project running 37% over budget.[182] As such, many of our projects may be riskier, such that it would require R&C costs to be above the 5% threshold.

Ofgem has not provided any quantitative analysis to demonstrate that 5% is appropriate. As part of our Business Plan submission, we presented third party analysis based on a much larger sample of schemes (sixty-three) evidencing the R&C allowances we are requesting with further supporting evidence provided in a subsequent SQ response. This analysis reviewed historical planned and actual released R&C costs for a sample of 33 load-related projects excluding 6 outliers and suggested an unweighted mean planned risk, and contingency of 10.9% for load-related expenditure, whereas the unweighted mean for released costs was 12.9%. Similarly, the analysis of a sample of 30 non-load related projects excluding 1 outlier determined an unweighted mean planned risk, and contingency of 8.9% of the project costs, whereas the average released costs were 9.2%. We note that such findings are not unique to us with SSEN-T indicating an increased construction risk position of [redacted] and NGET stating a risk contingency factor of [redacted] for early phase projects. There is no evidence that Ofgem has taken this information into consideration in DD.

It is critical that Ofgem's analysis is undertaken on a robust basis to ensure that sufficient allowances are provided. Such a low threshold places unnecessary risk on capex projects, which may result in delays to investment, or increased vulnerability to cost shocks and unforeseen circumstances that may result in overspend.

We note that the extension of ASTI delivery incentives to a broader range of load-related schemes in RIIO-T3, together with the new licence obligations on delivery of such projects will increase the risk borne by TOs during RIIO-T3 and as such is inconsistent with a 5% allowance for R&C which is a lower value than the 7.5% for RIIO-T2 and the values put forward in the TO forecasts.

Ofgem has noted that it has "found significant variance in the approaches taken by each TO in terms of costing methodology, manifesting in high variance of the requested risk costs. Broadly, we noted very limited justification within EJPs for particularly large risk costs, with minimal justification for the quantum of these costs." Ofgem has presented no analysis supporting this finding of significant variances, while, as noted above in our Business Plan, we conducted analysis of sixty-three historical schemes covering both load and non-load-related capex in order to determine the appropriate R&C percentages to apply. We also provided further analysis in response to SQ113. We would expect Ofgem as a minimum to show analysis explaining why our analysis and forecasts are inappropriate based on numerical evidence rather than simply stating it is poorly justified. This means demonstrating that Ofgem has fully considered the merits of the analysis that we have provided. At this stage, we are concerned that Ofgem has not adequately taken into account or therefore given appropriate weight to all available evidence.

We also dispute Ofgem's assertion that changes to the TIM and newly proposed mechanisms remove the need for R&C allowances based on TOs' costing approaches. Ofgem has not provided any quantitative evidence showing the impact of these new mechanisms on R&C costs. Further, we fundamentally disagree with TIM being positioned in this way. The TIM is a mechanism that is aimed at incentivising efficiency and addressing additional risks outside the control of TOs. Its purpose is not to correct for flaws in Ofgem's allowance setting at a price control. We can therefore only conclude that the 5% Ofgem has specified is arbitrary and is in essence an additional unjustified efficiency challenge on us and the other TOs.

[181] Capital project risk is typically measured as over-run compared to budgeted cost and planned schedule, though can also encompass conformance to specification.
[182] Asvadurov, S., Brinded, T., Brown, T., Ellis, M., Knox, D., & Speering, R. (2017), 'The art of project leadership: Delivering the world's largest projects', September.

Consequently, the 5% ratio should not form the basis for future R&C allowances for capex projects that are funded through Ofgem's Uncertainty Mechanisms given the lack of any substantive basis for this proposed ratio.

ETQ 51 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 broadly agree with the assessment for Vehicles and Transport and Non-operational Property and have no additional comments.

ETQ 53 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 strongly disagree with several aspects of the proposed approach to quantitative assessment which, if unchanged will result in unfair and undeliverable allowances.

To the extent that Ofgem has used its unit cost approach, it will inevitably disallow expenditure as allowed unit costs cannot – for any one category of cost – be set above submitted unit cost but may be set below them. Further, the degree to which Ofgem disallows costs across the industry reflects an arbitrary judgment on materiality thresholds, with no evidence whatsoever that the resulting disallowances correspond to the degree of inefficiency included in the TOs' business plans. Rather, Ofgem has applied a simple, mechanical procedure, which relies on arbitrary parameters that disallows costs without demonstration of efficiency.

The use of the lower unit cost between RIIO-T2 and RIIO-T3 is flawed

The use of the lower unit cost between RIIO-T2 and RIIO-T3 is flawed as it ignores any changes to the cost environment or cost pressures facing TOs in RIIO-T3 relative to RIIO-T2 (resulting in higher forecast unit cost). Ofgem has also stated in its assessment of Load and Non-load related capex, that '[Ofgem] considered it important to account for potential high volatility across periods… using RIIO-T3 data only where there were concerns that there has been a structural break across periods[183]' , indicating that Ofgem acknowledges the cost environment could be different in RIIO-T3, and that this would have to be accounted for. However, Ofgem has failed to apply the same logic to NOCs, resulting in an unexplained inconsistency.

This approach also implies that Ofgem considers all TOs' unit costs should be strictly decreasing over time, and any increases in unit costs would be deemed as 'inefficiency'. It also implies that Ofgem considers past unit cost trends to be reliable predictors for future unit costs, which also results in perverse incentives. Indeed, Ofgem concedes that this assumption may not be valid for certain asset categories, as it states "by applying the RIIO-T2 approach, for ten asset categories, modelled costs were significantly lower than submitted costs. This suggested that in these cases historical costs might not be a good indicator of RIIO-T3 costs"[184].

If unit costs do vary over time – both upwards and downwards – for reasons beyond TOs' control and unrelated to efficiency, Ofgem's approach will systematically disallow upward changes in efficient costs, while setting allowances that reflect reductions in unit costs. The mechanism Ofgem proposes to do this, i.e. crudely taking the minimum of the unit cost achieved in RIIO-T2 and forecast for RIIO-T3, is entirely mechanistic and fails to analyse the reasons for changes in unit costs over time. Further, the assumption that unit costs should be strictly decreasing over time is a double count of the application of OE which is also applied to NOCs costs.

Ofgem has failed to consider evidence of market cost pressures

We provided justification for increases in some costs on account of information from contractual negotiations (vegetation management) or based on actual costs (substation electricity). These justifications do not appear to have been considered in the assessment of costs. Ofgem should review

[183] Ofgem RIIO-3 DD ET Annex 5.26
[184] RIIO-3 DD – Electricity Transmission 5.70

the justifications provided – on a line-by-line basis – to ensure its cost assessment results in allowances which enable essential works under current market conditions.

Ofgem's reductions result in undeliverable programmes and cannot be considered as efficiency tests

We support Ofgem's role in ensuring value for consumers but in the application of cost assessment to NOCs, it has failed to ensure that resulting allowances are realistic and allow necessary works to be completed. For example:

- 400kV OHL Faults: the allowed cost is **11%** of the submitted cost.
- Civils maintenance: the allowed cost is 66% of the submitted cost.
- Vegetation management: an activity critical for resilience and public safety has only 57% of the costs (from contract negotiations) allowed.

In proposing these costs, Ofgem has failed to undertake any reasonable verification that its model is truly testing efficiency and is free from irrational outcomes.

Ofgem's annual average cost approach fails to account for increases in workload between RIIO-T2 and RIIO-T3

Ofgem calculates the annual average cost by dividing TOs' total cost in a cost area across both RIIO-T2 and RIIO-T3 by 10 and sets this annual average cost for each year of RIIO-T3, with the intention to address cost increases from RIIO-T2 to RIIO-T3. However, calculating the annual average cost in this way fails to account for changes in workload from RIIO-T2 to RIIO-T3 and the RIIO-T2 workload influences allowances for RIIO-T2. Therefore, while averaging the total costs over 10 years can partly mitigate the problem of a large (legitimate) increase in unit cost, it does not account for any rise in total costs resulting from increased workload. In fact, adopting the annual average cost approach can reduce TOs' allowances in instances where RIIO-T3 workload exceeds RIIO-T2 workload, because the lower RIIO-T2 workload reduces the annual average cost. A clear example of this is in substation electricity costs where the number of installations to which this cost relates doubles during RIIO-T3 (as advised in our business plan) but a simple historical average approach is adopted which fails to account for this.

Ofgem's annual average cost approach can result in lower allowances than modelled unit costs
A further flaw in Ofgem's methodology is caused by the application of the annual average approach to *all* TOs when triggered by a *different* TO. As noted in Ofgem's response to DDQ SPEN59, we have unit costs set by the unit cost approach but these are subsequently reduced because another TO has triggered the annual average approach for this activity. This is manifestly unfair and if Ofgem retains the two approaches, a valid modelled unit cost (subject to our view that this approach is itself flawed as it is already potentially reduced by irrelevant factors) must not be reduced even further due to another TO's particular circumstances.

Proposed Improvements

The quantitative assessment produces unfair and undeliverable allowances and must be revised:

- Qualitative justification for unit cost increases must be considered on a line-by-line basis for all cost categories.
- The 'lower of' approach must be replaced by an approach which is more aligned with load and non-load capex assessment.
- There must be a reasonableness test to identify and correct modelling outcomes that result in undeliverable allowances.
- The annual average cost approach must account for workload changes between periods.
- The annual average cost approach must not award lower allowances than the unit cost assessment, assuming that the flaws in the unit cost assessment are first rectified.

ETQ 54 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?

As discussed in ETQ 53 we consider that the quantitative benchmarking approach is flawed, fails to consider relevant factors and has erroneously reduced costs for Faults, Inspections, Maintenance, Repairs and Vegetation Management where there are clear reasons for variances from historical costs which were explained to Ofgem in our business plan.

Detailed examination of Ofgem's NOCs model has highlighted where this quantitative benchmarking approach has failed to consider aspects such as actual increases currently being experienced in market-tested costs, actual and proposed contract costs, volumes in maintenance plans, increased size of the network and additional expenditure requested and discussed in the Strategic Commentary for these tables. All of these factors were used when building our RIIO-T3 Business Plan.

An example of this is in Vegetation Management where Ofgem's DD costs for RIIO-T3 have simply used the average RIIO-T2 costs when our RIIO-T3 BP commentary specifically stated that current contract negotiations for Vegetation Management were indicating rates significantly greater than current costs.

As a result, we suggest that a qualitative approach, using the evidence presented should be considered alongside the quantitative cost assessment for all NOCs costs.

ETQ 55 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 do not consider that the proposed thresholds are appropriate for the assessment of NOCs.

Ofgem's selection of the materiality thresholds is arbitrary. Ofgem states that "we carried out sensitivity analysis on the data and concluded that the most impactful thresholds that we tested ranged from 15 to 30 percent and from £0.5m to £2m. We tested the impact on modelled costs using each combination of percentage and monetary thresholds and found that using thresholds of 25% and £1m was the most appropriate approach. We looked at the range of modelled costs when using each combination of thresholds and 25% and £1m resulted in modelled costs roughly in the middle of this range for all TOs.". Hence, as opposed to assessing what the appropriate threshold is to use the annual average cost approach, Ofgem's stated justification is simply a comment on how impactful different thresholds might be in affecting the outcome of the cost assessment.

Given that one of Ofgem's materiality thresholds is expressed in monetary terms (£1m difference between RIIO-ET3 submitted costs and modelled costs derived by the RIIO-ET2 approach), cost areas with lower costs are less likely to be able to reach the materiality thresholds. Despite having smaller costs, in aggregate these cost areas may still form a significant portion of the TOs' cost base because Ofgem's cost assessment disaggregates costs into many, low unit cost areas.

Ofgem's only justification for employing a monetary threshold in addition to the percentage threshold is that "employing a percentage threshold would mean at least 50% of assets moving to an average costs approach". This justification is effectively a "goal-seeking" approach, whereby Ofgem has a certain share of costs to which it is willing – for reasons not articulated in the DD – to apply the annual average cost approach, which necessarily leaves some cost categories assessed using a method that bakes in the implausible assumption that unit costs only ever increase due to reductions in efficiency.

Existence of a technical error in NOCs analysis
We also note that Ofgem's proposed approach for NOCs sets all allowed unit costs to zero in cases where historical or forecast volumes are not available (reported as 0), even when the total cost of that category is positive. The result is to understate our costs for sub-categories where volume data was not available. As highlighted above, this can be seen in the treatment of 132kV overhead line faults. It is plainly wrong to assume a unit cost of fault resolution of £0 per fault and therefore this represents an error in Ofgem approach.

Failure to address impact of significant variances in costs
Of the NOCs cost areas assessed via the unit cost approach, there is significant variation in unit costs between RIIO-ET2 and RIIO-ET3. This includes in cost categories where the materiality thresholds set by Ofgem are not met for annual average cost approach to be used. This approach fails to disentangle genuine efficient cost increases from inefficiency. Our unit costs were volatile across ET2 and ET3 (substation protection and control, OHL 400kV, Substation FACTs and vegetation management 275kV).

In these areas, Ofgem's analysis makes no attempt to assess whether such changes are reasonable, and instead systematically disallows them. This is a fundamental weakness of the threshold approach and a reflection of: (1) the impact of adopting an overly simplistic approach where Ofgem's thresholds are not met; and (2) relying on the false premise that unit costs can only fall over time.

ETQ 56 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?

Overall, we welcome the introduction of this qualitative assessment framework, and the range of categories included in the NOCs Other Table and Flood Mitigation Table, e.g. climate resilience costs (including flooding), biodiversity net gain and carbon offsetting.

We have a concern that the assessment used for Substation Electricity does not take into account relevant information. The approach used appears to be the same as the quantitative approach use in the other NOCs tables and discussed in ETQ 53 and 54. The approach used appears to take the RIIO-T2 average cost to provide the RIIO-T3 costs in Ofgem's DD which is not correct. The RIIO-T3 costs submitted in our RIIO-T3 BP used the most up to date electricity cost based on current rates. Ofgem's approach does not take this into account.

As discussed in ETQ 54 Ofgem should consider applying this qualitative approach to 8.1 Faults, 8.2 Inspections, 8.3 Maintenance, 8.4 Repairs and 8.6 Vegetation Management, by taking account of the evidence of increasing costs in our submission.

ETQ 59 Do you agree with our proposal to remove the opex escalator for RIIO-ET3?

While we previously highlighted the need for reform of the opex escalator, notably with respect to ensuring the appropriate funding of contractor indirects, we regarded it as having an ongoing role in RIIO-T3. This view was in line with Ofgem's position set out in the SSMD that the mechanism should be retained but reviewed to improve its parameters.

Now that Ofgem has signalled a change to its position, our principal concern with Ofgem's proposal to remove the mechanism is that the alterative presents increased risk of underfunding CAIs as highlighted in our response to **ETQ58**. If these shortcomings could be addressed by improvements to the UIOLI mechanism, then we can see the justification for removing the opex escalator.

ETQ 66 Do you agree with our assessment approach for Physical Security? If not, how should we assess these costs?
While we agree with Ofgem's quantitative assessment and the level of cost aggregation, we do not agree with the proposed approach to setting the allowances. We would like to note that, contrary to the statement in the DD, we did submit works for RIIO-T3 baseline approval (Project Reference "SPNLT20298"). However, the associated RIIO-T2 costs have not been allowed. This treatment is inconsistent with all other investment types, where RIIO-T2 expenditure has been included in the first year of RIIO-T3. We believe this to be an error and we welcome Ofgem's indication in its response to supplementary question SPEN66 that this is fact the case. The new sites were identified by DESNZ in September 2024, following a review of the criteria defining Critical National Infrastructure (CNI). As this notification came after the re-opener window defined in Licence Special Condition 3.4, it was not possible to include them in the RIIO-T2 re-opener. Therefore, they were appropriately included in the RIIO-T3 baseline plan. The RIIO-T2 expenditure is essential to enable timely progress toward delivering these sites by their forecast completion dates.

SPTQ 2 Do you agree with our proposal to introduce this PCD (Non-Lead Assets & Switchgear PCDM) for SPT?
No, we do not agree with the proposal to introduce this PCD for SPT. Ofgem has approved the needs case in full but has not provided any justification for designating these schemes as PCDs. Ofgem states in paragraph 2.22 that there is uncertainty in the delivery of these schemes. We have provided full written Engineering Justification Papers (EJPs) in addition to the portfolio EJPs detailing the scope of works and there is no uncertainty in the delivery of the schemes. Therefore, we believe they should remain part of the baseline.

A full rationale on the proposed scope and intervention types for the Schemes SPNLT20281 and SPNLT20282 is captured under respectively written and portfolio EJPs and SQ “SPEN076”. The statement in table 7 that the details of the refurbishment are not specified is not correct and the following summarises the reasoning for the defined intervention type for the identified assets:

- As outlined in Ofgem’s *RIIO-ET2 Regulatory Instructions and Guidance: Glossary v1.4 (All TOs)*, refurbishment interventions are intended for individual asset replacements rather than entire schemes. Accordingly, these interventions have been classified as either minor or major refurbishments.

- Targeted devices identified for intervention under SPNLT20282 are justified under attached EJP in SQ SPEN076.

The inclusion of Health Index 1 devices is explained in our response to Ofgem’s supplementary question SPEN076 as the result of a full optioneering exercise to provide wider benefits.

SPTQ 6 Do you agree with our proposed unit rates?

We do not agree with the Ofgem DD proposed unit rates. The combination of the rates and materiality threshold means that the volume driver mechanism serves no purpose in the RIIO-T3 framework. Applying the proposed rates to our contracted portfolio results in an overall underfunding of £94.52m. Although this accounts for 84% of the contracted projects, the materiality of the underfunding is a major concern for us. This is driven by the proposed rates, as well as the size of the threshold.
There are specific areas of concern, including:

- Removal of the £1.7m fixed cost component.
- Use of a simple inflationary uplift for new OHL and reconductoring works, despite a previously stated lack of supporting data.
- A 37% reduction applied to underground cable works beyond 1km, despite rising UGC costs since RIIO-T2. The allowance should consider the real cost of UGC.
- Rates for new OHL build should consider the different voltage levels as well as having separate rates for steel tower and wood pole designs.
- The increased availability of new OHL conductor technology e.g. High Temperature Low Sag (HTLS) to provide significant increases in capacity needs to be acknowledged as a unit cost in its own right.
- Similarly, voltage levels should be considered for underground cable work.

The volume driver does not support substations as the £/MVA unit rate does not align with the total cost. As it stands, only 56% of the substations required in RIIO-T3 would be funded under the VD mechanism. We suggest an alternative that takes the total work required into account, rather than simply using the MVA rating.

While we believe that the enhancements outlined above would provide more cost-reflective outcomes, as a minimum, the rates should be updated as follows:

Table 3-1 - Volume driver components and unit costs

The rates presented above have been calculated using the same regression model used by Ofgem to identify and exclude outliers. This approach is expected to result in approximately 64% of our Contracted Portfolio being funded through the volume driver uncertainty mechanism. Consequently, our proposal delivers a more balanced outcome than Ofgem's, which would result in an underfunding of our contracted portfolio by £94.52 million. Our proposed rates yield an overall performance of £28.51 million (2.8% of the total VD costs) within a materiality threshold of ±8.847, offering a more accurate reflection of the volume driver components.

Proper calibration of the volume driver rates is critical to determining the number of projects that would require funding through Load Reopeners. This, in turn, directly influences the appropriate sizing of the UIOLI funding pot.

Chapter 4 - Cost Assessment – IT and Telecoms

4.1 Summary

4.1.1 Ofgem's assessment of IT&T covers three activities within the TOs' Business Plans:

1. Operational Technology (NOCs)
2. Business Support IT&T, and
3. Non-Op Capex IT & Telecoms: Devices and Network Hardware Refresh

4.1.2 This has been carried out through review of the TOs' submitted project proposals. Ofgem has conducted a qualitative assessment with third party consultants conducting a review of costs.

4.1.3 In general, we are concerned that Ofgem's lack of transparency regarding its review of IT&T costs means that the process applied is neither robust nor consistent.

4.1.4 For Operational Technology Ofgem disallowed approximately 50% of the costs, with £61.11m approved of the £123.8m forecast. Business support IT&T costs were subject to a 49% reduction, with £43.5m approved of the £84.5m submitted. For non-operational capex, SPEN submitted £5.5m, and Ofgem's consultants again recommended a 49% reduction, only approving £2.8m. The magnitude of these reductions significantly impairs our capacity to operate efficiently. Without appropriate cost coverage, our ability to maintain effective operations could be jeopardised. The rationale for these substantial reductions is clearly insufficient. Ofgem's qualitative approach to assessing non-operational IT&T Capex is brief, citing only 'fair cost evidence' for non-operational costs and 'poor evidence' for Business Support Costs (BSCs), without further explanation.[185] There are also limited details provided in the modelling files, where projects are rated 'red', 'amber', or 'green' against a set of criteria without explanation. In addition, we have not received the files documenting the results from the qualitative review of the proposed projects, which hinders our ability to understand the basis for Ofgem's ratings or to explore improvements to the project proposals submitted.

4.1.5 We consider the issues in each of these areas of IT&T, in turn, below, and how they should be addressed by Ofgem.

4.2 Operational Technology (OT)

4.2.1 We support Ofgem's decision to undertake a technical review of individual investment proposals. However, we have significant concerns regarding the cost assessment methodology applied to IT&T investments, particularly Operational Technology (OT), which is reported under Network Operating Costs (Table 8.9). OT systems are critical infrastructure, essential for maintaining grid stability, public safety, and national security. Underfunding these systems poses a serious risk to the reliability and resilience of the transmission network.

4.2.2 The cost assessment framework lacks clarity, consistency, and transparency. It introduces retrospective criteria not previously consulted on or outlined in RIIO-T3 guidance. Ofgem cannot rely on undisclosed criteria for its assessment, to do so would be procedurally unfair, as such it should be removed from the assessment

4.2.3 The methodology evaluates three dimensions — validity of the need case, strength and robustness, and appropriateness of cost levels — using a RAG rating system. RAG assessments against each scheme were provided to companies after the DD publication but without sufficient rationale, making it difficult to interpret or respond effectively. Full details of our views on the assessment approach have been included in the response to ETQ 52 of this consultation. However, we summarise below the key concerns with the methodology:

[185] Paragraph 3.7, Ofgem (2025), 'RIIO-3 DD - Scottish Power Transmission (SPT), July.

1. **Validity of the Need Case**: The operational rationale component overly focuses on obsolescence or trade-offs, disadvantaging cases aimed at enhancing resilience of critical energy infrastructure. We recommend this rationale to be reviewed.

2. **Strength and Robustness of the need case (Economic Case)**: The requirement for Cost Benefit Analysis (CBA) was not specified in guidance, yet its absence results in penalisation. It is inappropriate for Ofgem to adopt this approach in its assessment. We recommend its removal from the assessment. Several schemes—T3SGOINF01&02, T3SGOTEL05U, and T3SGOTEL06U—received red or amber ratings despite being minimum necessary interventions to maintain and securely operate the network, leading to funding reductions of up to 75%.

3. **Cost Appropriateness**: The assessment of scope, certainty, and assurity has been inconsistently applied. Competitive tendering was used to derive cost estimates yet, without justification, these were rated poorly. Ofgem's own commentary acknowledges appropriate unit costs and volumes yet applies blanket reductions which are unsupported by any transparent rationale or evidence.

4.2.4 Now that we have sight of the assessment criteria, we have revised and are resubmitting our Engineering Justification Papers (EJPs) [186] to provide enhanced detail on optioneering, deliverability, and cost certainty. We urge Ofgem to reassess the ratings and funding allocations to ensure critical infrastructure is adequately supported, in line with RIIO-T3's strategic objectives.

4.2.5 Ofgem's funding methodology applies a scoring system weighted 40% to Economic Case and 60% to Cost Assessment, resulting in four funding thresholds (Low, Mid, High, Upper). However, the rationale behind these thresholds remains undisclosed, raising concerns about transparency and fairness.

4.2.6 The proposed funding adjustments lack justification based on efficiency or risk analysis, potentially undermining the delivery of critical investments. This is particularly concerning for Operational Technology (OT) systems, where underfunding could compromise the reliability and security of the transmission network. The current approach diverges from RIIO-T3's strategic principles, which emphasise resilient, secure, efficient, and affordable infrastructure.

4.2.7 Other key issues identified include:

- **Misalignment between Business Plan guidance and assessment criteria.**

4.2.8 The Operational Technology (OT) EJPs were developed in line with Ofgem's RIIO-ET3 Business Plan Guidance, specifically Annex 1: Investment Decision Pack (IDP). However, the assessment criteria were only released after the submission deadline in December 2024 without advance notice, resulting in a misalignment between the guidance followed and the evidence now required for full funding approval. TOs were not given the opportunity to revisit their submissions following the disclosure of the assessment criteria.

4.2.9 Key concerns include:

- Late disclosure of assessment criteria, which has disadvantaged submissions by applying expectations not originally communicated.
- Inconsistency with atypical EJP guidance, where acceptable evidence types (e.g., studies, stakeholder views) were overlooked in favour of more prescriptive criteria.
- Unjustified penalisation for lack of Cost Benefit Analyses (CBAs), despite CBAs not being mandated for atypical projects, leading to reduced scores and funding.

4.2.10 This misalignment has created an unfair evaluation environment, potentially jeopardizing critical OT investments necessary for network reliability and security.

[186] Please refer to updated Operational Technology EJPs in Annex 5.1 to 5.13

- **Errors in the application of the assessment methodology.**

4.2.11 Incorrect thresholds were applied to the project, Transmission PowerOn Functionality. This project was given a combined score of 2 and hence should have been given a funding factor of 75% but was instead given a funding factor of 50% in Ofgem's modelling files. We note that the project, AEMS Circuit Rating Management System (CRMS) Update, also achieved a combined score of 2 and was correctly assigned a funding factor of 75%.

4.2.12 Additionally, there are errors in the incorrect application of the results of an assessment of a project in Ofgem's modelling files. In the IT&T cost assessment document, it states that projects worth less than £0.5m would be given full funding if their needs case was rated as amber or green and the project, PowerOn Resilience Discovery, was proposed to have 100% funding. However, this project was recorded as being granted only 25% funding in the modelling files. The IT&T inputs values in the modelling files are not fully aligned with the submission values as per BPDT 8.9 producing mistaken outputs. These errors affect the average proportion of IT&T expenditure approved, which is then applied to all IT&T expenditure to calculate allowed costs. It is important that these errors are corrected in the modelling files to accurately reflect Ofgem's stated methodology.

- **Inconsistent treatment of OT costs in the Draft Determination.**

4.2.13 We raise concerns about the classification and assessment of Operational Technology (OT) within Ofgem's Draft Determination. Although OT has been categorised under the Network Operating Costs (NOC) cost area, it is assessed using the IT & Telecoms (IT&T) cost methodology - an approach that does not fully reflect OT's strategic scope and function. Key concerns include:

- Misaligned classification: OT is operationally grouped under NOC but evaluated using IT&T criteria, creating confusion and undermining its strategic importance.
- Broader strategic role: OT investment includes operation and maintenance to keep the infrastructure necessary to keep our transmission network Protection, Control and Monitoring systems operational, but also plays a vital role in digitalisation and Net Zero delivery.
- Inconsistent documentation: OT is variably labelled as "IT & Telecoms Operational Technology" and sometimes allocated under "Non-Op Capex," as seen in supplementary materials like SPEN003 DDQ response.

4.2.14 **Call for clarity**: We recommend Ofgem provides clearer, standalone definitions for Data and Digitisation, IT & Telecoms, and Operational Technology to ensure OT is assessed appropriately in line with its critical role in network reliability and security.

4.2.15 This inconsistency in classification and methodology risks undervaluing OT's contribution to strategic infrastructure goals and highlights the need for more transparent and coherent guidance.

4.3 Business Support IT&T

4.3.1 The justification for the substantial reductions is inadequate, citing only "poor evidence" for BSCs without further explanation. There are also limited details provided in the modelling files, where projects are rated 'red', 'amber', or 'green' against a set of criteria without explanation. In addition, we have not received the files documenting the results from the qualitative review of the proposed projects, which hinders our ability to understand the basis for Ofgem's ratings or to explore improvements to the project proposals submitted. Ofgem has therefore failed to sufficiently disclose the reasons for its decision making. We set out our reasons why we disagree with the assessment approach in further detail in Section 4.2 Operational Technology.

4.4 Non-Op Capex IT & Telecoms: Devices and Network Hardware Refresh

4.4.1 Again, the justification for the substantial reductions is inadequate. Ofgem's qualitative approach to assessing non-operational IT&T capex is brief, citing only "fair cost evidence". There are also limited details provided in the modelling files, where projects are rated 'red', 'amber', or 'green' against a set of criteria without explanation. In addition, we have not received the files documenting the results from the qualitative review of the proposed projects, which hinders our ability to understand the basis for Ofgem's ratings or to explore improvements to the project proposals submitted. We set out our reasons why we disagree with the assessment approach in further detail in Section 4.2 Operational Technology.

COST ASSESSMENT – IT & TELECOMS QUESTIONS

ETQ 52 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?

In general, we are concerned at Ofgem's approach to its review of IT&T costs, which raises questions about the correctness of its process and outcomes**.**

Ofgem's assessment of IT&T covers three activities within the TOs' Business Plans:

- Operational Technology (NOCs)
- Business Support IT&T and
- Non-Op Capex.

This has been carried out through expert review of the TOs' submitted project proposals supported by third-party consultants. In general, we are concerned at Ofgem's lack of transparency regarding its review of IT&T costs, which raises questions about the robustness of its process.
We have significant concern that Ofgem has not considered resilience within the assessment approach and criteria for IT&T projects. The CP2030 action plan[187] makes clear reference "As we rapidly deploy new infrastructure, we will maintain high levels of resilience and security ..... we will continue to work with industry, regulators and other stakeholders to improve and maintain the resilience of old, new, and future energy infrastructure". The importance of the resilience criterion is further consolidated given the expected publication by DESNZ of the 'energy resilience strategy' this summer. For Operational Technology Ofgem **disallowed approximately 50% of the costs**, with £61.11m approved of the £123.8m forecast. Business support IT&T costs were subject to **a 49% reduction**, with £43.5m approved of the £84.5m submitted. For non-operational capex, SPEN submitted £5.5m, and Ofgem's consultants again **recommended a 49%** reduction, only approving £2.8m.

We consider the issues for each of these areas of IT&T in turn:

Operational Technology (OT)
We support Ofgem's decision to conduct a technical review of individual investment proposals. However, we **strongly disagree** with the proposed cost assessment methodology. It is important to note that the IT&T review encompasses both Non-Operational IT and Operational IT & Telecoms, reported under Network Operating Costs (Table 8.9 – Operational Technology). While increasingly interconnected, OT and Non-Operational IT serve distinct purposes. OT systems must remain continuously available to ensure a reliable electricity supply. This distinction is critical and should be reflected in the evaluation of need cases.

Our OT systems are vitally important infrastructure. Any disruption could compromise public safety and national security and network operation. These systems are essential for protecting people, maintaining grid stability, and enabling emergency restoration. Underfunding them poses a significant risk to the reliability and security of the electricity network.

Inappropriate and Unclear Cost Assessment Framework
We consider the IT&T cost assessment framework to be inappropriate, inconsistent, and insufficiently defined, leading to outcomes that do not serve consumer interests. While the methodology claims to build on RIIO-2, it is important to highlight that OT investments (classified under Non-Load Investment in RIIO-T2, Table C2.2) were not previously subject to this form of assessment. There was no prior consultation or guidance indicating that specific information would be required to achieve high ratings. It is therefore unreasonable and impermissible to assess companies against unclear and retrospective criteria and applying requirements with hindsight does not follow regulatory best practice.

The assessment is based on three dimensions:

- Validity of the need case
- Strength and robustness of the need case

187 Clean Power 2030: Action Plan: A new era of clean electricity

- Appropriateness of cost levels

Each is scored using a RAG (Red-Amber-Green) rating. However, the methodology lacks transparency. Despite requesting the details underpinning the detailed RAG assessments immediately after publication of the Draft Determination, we only received them on 29 July 2025, and they were not accompanied by suitable rationale specific to each need case. This makes it difficult to understand the basis for the scores or to respond meaningfully.

- The validity of the need case

Ofgem assesses the need case using a pass/fail rating based on strategic rationale, operational rationale, and effectiveness. While the strategic rationale and effectiveness criteria are reasonable, the operational rationale is flawed. It focuses on:

- Obsolescence and asset life extension
- Complementarities or trade-offs with other expenditures

This approach penalises projects not driven by obsolescence or lacking trade-offs, such as those aimed at enhancing network resilience through route diversity. These projects are nonetheless essential. We therefore recommend that Ofgem review the operational rationale used in the assessment, as it does not accurately reflect the true value or necessity of these investments.

Furthermore, some RAG scores are inexplicable. For example, our RIIO-T3 T3SGOINF01&02 Network Infrastructure Refresh and Server Management scheme received an 'amber' rating for effectiveness, despite being a continuation of a proven lifecycle refresh strategy. Similarly, we do not agree with other scores given to our investment cases and would like to challenge these ratings and discuss the relevant scores. We have requested a bilateral with Ofgem for this matter.

- The strength and robustness of the need case (Economic Case)

This dimension is assessed based on the Economic Case, contributing 40% to the final score. It includes:

- Value for Money: Based on Cost Benefit Analysis (CBA) results. The absence of a CBA appears to result in a 'Red' rating whether or not a CBA is relevant.
- Optioneering: Based on the range of options considered and evidence supporting the preferred one.

We dispute the *value for money* assessment. The Business Plan guidance did not require a CBA for this type of investment (typically supported by EJPs). CBAs can be useful tools in the evaluation of multiple options which have differing costs and benefits, where the benefits can be objectively and accurately monetised. The nature of many of the investments in OT means that their *value for money* is not best demonstrated by a CBA. Penalising companies for not including one is therefore unjustified and unreasonable, and we recommend excluding these criteria from the assessment.

Several of our OT schemes—T3SGOINF01&02, T3SGOTEL05U, and T3SGOTEL06U—have received red or amber RAG ratings for optioneering, despite proposing the minimum necessary interventions to maintain compliance with security standards, preserve system reliability, and ensure network safety. These schemes were developed with a clear focus on delivering essential outcomes with minimal cost and complexity. Nevertheless, they have been subject to funding reductions of 75% and 50%, which risks undermining the continued safe and reliable operation of the transmission network. The rationale behind these scores remains unclear and appears inconsistent with the nature and intent of the proposed investments.

Now that we have sight of the assessment criteria, we have reviewed the optioneering sections of our EJPs[188] and are re-submitting those alongside this response to ensure they clearly articulate the decision-making process undertaken, including the rationale for the selected options.

The appropriateness of the cost levels associated with the proposed investment option

[188] Please refer to updated Operational Technology EJPs in Annex 5.1 to 5.13

Ofgem's cost assessment is structured around three elements:

- Scope: Clarity and maturity of the proposed scope
- Certainty: Presence of a delivery plan, resources, outputs, and risk mitigation
- Assurity: Confidence in cost estimates and potential consumer impact

While we support the principles of certainty and assurity to ensure fair costs for consumers, the execution of this assessment has been inconsistent and unclear.

The *certainty* assessment criteria is then split into three elements in the detailed RAG assessments provided by Ofgem, which are 'assessment on delivery certainty', 'resourcing and project planning' and 'risk'. The distinction between "delivery certainty" and "resourcing and project planning" is unclear, as both appear to assess similar aspects yet yield differing scores across investments. We request clarification on the criteria applied and a review of the scores assigned.

The *assurity* assessment is then split into three elements in the detailed RAG assessments provided by Ofgem, which are 'efficiency/cost effectiveness', 'benchmarking' and 'cost estimation'. These elements aim to evaluate cost efficiency through competitive pricing, benchmarking, and confidence in estimates.

While we agree with the intent, the application has been flawed. Many of our cost estimates—derived from competitive tendering—have been rated 'Red', despite commentary in the supporting file acknowledging the competitive procurement process. Ofgem has confirmed no additional cost benchmarking exercise was undertaken (DDQ SPEN03), yet our tenders tested the market and selected the lowest-cost technically compliant providers. This should be recognised as evidence of cost efficiency, and we request reassessment of the cost assurity ratings.

The cost estimates presented by us have the level of granularity required by Ofgem, as defined by the design of BPDT8.9. However, some elements of the cost assessment framework, such as the evaluation of estimation robustness, appear to assess the granularity of the cost data itself. It is therefore unreasonable to reduce the score based on a perceived lack of information that was not requested in the Business Plan guidance.

Furthermore, the DD presents conflicting information. Ofgem acknowledges appropriate unit costs and volumes, yet applies blanket reductions due to perceived lack of detail—details not specified in the original guidance. For example, in the Business Plan Incentive (BPI) Stage B assessment for Network Operating Cost (NOC): Operational Technology, Ofgem notes "adequate rating for unit cost and volumes justification" but assigns 'Red' ratings for cost assurity to 12 out of 13 schemes. This contradiction undermines the credibility of the assessment.

We have applied a consistent cost allocation methodology across all OT asset categories. Strategic partnerships ensure effective operation and maintenance, including 24/7 Network Operations Centre support and delivery of key infrastructure projects. All framework contracts were competitively tendered, ensuring market-tested and efficient pricing. At the time of submission, the Telecoms tendering process was nearing completion, providing high confidence in cost accuracy. Each contract includes fixed rate cards for the full term, ensuring cost competitiveness.

With the cost certainty criteria now clarified, we have updated our EJPs[189] to include enhanced detail on deliverability, resource planning, and implementation. These updates are clearly marked for Ofgem's review.

We also note that the final column in Ofgem's detailed analysis—"cost estimation consistent with the plan?"—is frequently marked "No." We dispute this assessment and confirm that all cost estimates align with the proposed investments and Business Plan Data Tables.

Calculation of the score thresholds and funding adjustment

Ofgem's scoring methodology assigns 40% weight to the Economic Case and 60% to Cost Assessment, resulting in four funding thresholds: Low (25%), Mid (50%), High (75%), and Upper (100%) (Please refer to Table 4-1). However, the rationale behind these thresholds has not been disclosed.

[189] Please refer to updated Operational Technology EJPs in Annex 5.1 to 5.13

Table 4-1 - Ofgem thresholds for funding based on combined score

	Combined Score Threshold >=	RAG Funding Factor
Upper	2.5	100%
High	2	75%
Mid	1.5	50%
Low	1	25%

Source: Ofgem (2025), 'IT&T cost assessment', July, p.7.

Ofgem has a duty to adequately fund the efficient costs of need cases that they approve. The proposed funding adjustments are inappropriate and lack justification based on efficiency or risk analysis. Without transparency, these reductions jeopardise the delivery of essential investments.

Given the critical nature of our Operational Technology systems, underfunding poses a serious risk to the reliability and security of the transmission network. This approach deviates from RIIO-T3's strategic principles, which aim to support resilient, secure, efficient, and affordable infrastructure. The current methodology undermines these goals and threatens the integrity of the network.

In addition to our views on the cost assessment methodology, we highlight below additional points of consideration**.**

- A significant misalignment between the Business Plan submission guidance and the criteria used in the assessment framework.
- An assessment outcome that appears inconsistent, erroneous and lacking sufficient detail.
- Inconsistent treatment of Operational Technology costs throughout the Draft Determination.

Deviation from Business Plan Guidance

The Operational Technology (OT) EJPs were developed in accordance with Ofgem's RIIO-ET3 Business Plan Guidance, specifically Annex 1: Investment Decision Pack (IDP) Guidance. However, the assessment criteria were only made available ***after*** the submission deadline in December 2024. This has resulted in a misalignment between the information originally requested under the IDP Guidance and the evidence now required to achieve a score of 2.5 or higher—necessary for full funding approval under the IT&T investment criteria.

Furthermore, the assessment framework does not align with the atypical Engineering Justification Paper guidance outlined in Appendix 1 of the Business Plan Guidance. For example, page 15 identifies acceptable supporting evidence as including studies, narrative, industry letters of support, and stakeholder views. Despite this, the assessment appears to have applied more granular and prescriptive evaluation criteria. While Cost Benefit Analyses (CBAs) are explicitly required for other investment types, they are not mandated for atypical projects. Nevertheless, the absence of CBAs has led to significantly reduced scores for OT EJPs.

Incomplete and erroneous assessment

We also consider the assessment outcomes to be incomplete. Despite requesting access to the cost assessment models, benchmarking files and scheme-specific commentary, the information provided has been limited, raising concerns about the transparency of the process.

Additionally, incorrect thresholds were applied to the project, 'Transmission PowerOn 'Functionality'. This project was given a combined score of 2 and hence should have been given a funding factor of 75% but was instead given a funding factor of 50% in Ofgem's modelling files. We note that the project, 'AEMS Circuit Rating Management System (CRMS) Updates', also achieved a combined score of 2 and was correctly assigned a funding factor of 75%.

Second, there is an error in the incorrect application of the results of an assessment of a project in Ofgem's modelling files. In the IT&T cost assessment document, it states that projects worth less than £0.5m would be given full funding if their needs case was rated as amber or green and the project,

'PowerOn Resilience Discovery', was proposed to have 100% funding. However, this project was recorded as being granted only 25% funding in the modelling files.

Furthermore, the IT&T inputs values in the modelling files are not fully aligned with the submission values as per BPDT 8.9 producing mistaken outputs. These errors affect the average proportion of IT&T expenditure approved, which is then applied to all IT&T expenditure to calculate allowed costs. It is important that these errors are corrected in the modelling files to accurately reflect Ofgem's stated methodology.

Consistency in the treatment of Operational Technology expenditure

We note that Operational Technology (OT) has been categorised under the Network Operating Costs (NOC) cost area however assessed under the IT&T cost methodology. This classification does not fully reflect the scope and strategic function of OT. While the OT submission includes elements of operation and maintenance for the critical OT infrastructure such as fault response, inspections, maintenance, repairs, and service agreements—with a focus on their technological components—OT encompasses a broader remit. It plays a critical role in advancing digital capabilities and supporting our wider digitalisation strategy and Net Zero objectives.

Given this broader strategic context, we recommend that Ofgem provides clearer definitions of Data and Digitisation, IT & Telecoms, and Operational Technology. This would ensure that OT is assessed as a standalone function in a manner consistent with its critical nature in the reliability and security of the transmission network.

Throughout the DD documentation, Operational Technology (OT) is consistently reported under the NOC cost area and is often labelled as "IT & Telecoms Operational Technology" to differentiate it from non-operational technology. However, Ofgem inconsistently includes OT under the broader IT&T category while arbitrarily referencing either operational or non-operational costs. For instance, the supplementary Excel file accompanying response SPEN003 DDQ allocates proposed OT funding under "Non-Op Capex."

This inconsistency underscores the need for clearer guidance on the classification and assessment of OT within the DD framework.

Business Support IT&T

The justification for the substantial reductions is inadequate, citing only alleged "poor evidence" for BSCs without further explanation. There are also limited details provided in the modelling files, where projects are rated 'red', 'amber', or 'green' against a set of criteria without explanation for those criteria or how they were used to assess projects. In addition, we have not received the files documenting the results from the qualitative review of the proposed projects, which hinders our ability to understand the basis for Ofgem's ratings or to explore improvements to the project proposals submitted.

Non-Op Capex IT&T

Again, the justification for the substantial reductions appears inadequate. Ofgem's qualitative approach to assessing non-operational IT&T capex is brief, citing only "fair cost evidence". There are also limited details provided in the modelling files, where projects are rated 'red', 'amber', or 'green' against a set of criteria without explanation for those criteria or how they were used to assess projects. In addition, we have not received the files documenting the results from the qualitative review of the proposed projects, which hinders our ability to understand the basis for Ofgem's ratings or to explore improvements to the project proposals submitted.

With this lack of transparency, it is difficult to reconcile the apparently arbitrary major reduction in costs allowed with the robust evidence of costs we provided, via an independent assurer[190] which benchmarked our IT&T non-operational Capex against their independent benchmarks for these activities. In this report, it was noted that our IT & Telecoms non-operational capex has been benchmarked by Gartner against

[190] Gartner Consulting RIIO-T3 Assurance Report – Capital IT Programmes (submitted as part of our Business Plan)

their independent benchmarks for these activities, with 29 of 34 initiatives falling within the expected cost range, and only two projects falling outside of Gartner's upper cost estimate by 2%.[191] Additionally, 92% of projects in this category are competitively tendered, providing further evidence of efficiency embedded into costs.[192] Where there are genuine information deficiencies, we endeavour to rectify this using evidence of the assurance of our costs from Gartner and IBM.

[191] SPEN (2024), Cost Assessment and Benchmarking Approach, December, Section 7.1.3.
[192] SPEN (2024), Cost Assessment and Benchmarking Approach, December, Section 2.2.

Chapter 5 - Incentives

5.1 Incentives

5.1.1 Incentives, are an essential part of the RIIO framework to drive improvements in key areas, shifting behaviour of regulated network companies. This has been demonstrated in RIIO-T2 by SO:TO Optimisation ODI delivering in excess of **£110m in constraint cost savings** in the first 4 years of RIIO-T2, achieving **0 MWH** of Energy not supplied in the first 2 years of RIIO-T2 and being **above the target for Quality of Connections Survey** in each year of RIIO-T2. We had a clear ask of Ofgem for the RIIO-T3 incentive package:

"… encourage the behaviours required for RIIO-T3 and targets are challenging yet achievable"[193].

5.1.2 We are strongly supportive of the policy direction and intent from Ofgem in the incentive package. We believe the policy intent of the Output Delivery Incentives (ODIs) package recognises the challenge of delivering CP2030 including the connection of Clean Power and ensuring energy security in the UK. However, our bottom-up analysis and forecasts for each of the individual ODIs **demonstrates that the current ODI methodology as set out in the DD doesn't support the execution of this policy intent and in reality provides less opportunity for rewards than previous price controls due to the uncertainty of targets and implementation in the DD**. This does not align with Ofgem Impact Assessment, whereby Ofgem have factored in the increased scale of TOTEX in the incentive package. This risk is systemic, much of which is driven by Regulatory risks as outlined in Figure 1-2 (section 1.7.5) of this document which shows how regulatory risks have increased since RIIO-T2 and have increased further from SSMD to Ofgem's DD[194]. This is fully outlined in out Finance section which demonstrates that the 200 bps Ofgem has outlined is unachievable and 10 bps is much more likely (see Chapter 1, section 1.56).

5.1.3 We support Ofgem's adoption of our proposed Totex Incentive Mechanism (TIM) approach, prioritising risk management during this intense period of network and economic growth. As outlined in our proposal for the 'stepped TIM' which applies a higher TIM rate for an initial portion of overspend, with reduced rates for subsequent 'steps', the approach ensures a strong incentive to maintain efficiency in-period, whilst protecting consumers and TOs against windfall gains and losses due to exogenous supply chain and delivery challenges. Given the limited opportunity for outperformance in the ODI package, we do believe the stepped TIM should be considered on an asymmetric basis to increase TO's focus on efficiency savings for consumers at a time of unprecedented investment scale.

5.1.4 This section outlines:

- evidence that Ofgem's policy intent has not been executed in DD,
- clear asks to Ofgem required to deliver a challenging yet achievable ODI package evidenced by our bottom-up analysis
- the individual question responses in relation to ODI

<u>Ofgem's t-3 DD's ODI execution does not achieve its policy intent</u>

5.1.5 Our clear ask to Ofgem was focussed on a) encouraging the behaviours required for RIIO-T3 and b) ensuring targets are challenging yet achievable.

a) <u>Does the RIIO-T3 package encourage the behaviours required during RIIO-T3?</u>

5.1.6 We strongly support Ofgem's policy intent of the RIIO-T3 ODI package. We support the focus on delivering CP2030, on time or early, through a connections incentive and CSNP-F, ensuring energy resilience, optimising outages to reduce constraint costs and minimising the impact on the

[193] Following submission of our Business Plan in Ofgem working and senior level engagement from January – August 2025

[194] Annex 2.5. S&C (2025). *2.5 SPEN - Relative Risk Assessment - Summary Report*

environment (IIG). We welcome the new delivery incentive encouraging delivery in an innovative way.

5.1.7 We believe the scope and calibration of incentives needs refinement in key areas. The innovative delivery incentive for example should not only focus on the timing of project delivery but also projects are developed and delivered, ensuring the environmental and community impacts are minimised. This was a critical part of the Holistic Design Methodology that delivered ASTI and is a key aspect of the Central Strategic Network Planning Methodology going forward – as was recommended by the Electricity Networks Commissioner Nick Winser[195]. This is recognised in part by Ofgem with the 'NESO collaboration' but needs to go further, we propose expanding this to 'stakeholder collaboration (inclusive of the NESO)'.

5.1.8 We have also provided evidence (annex 8.1) that the scope and calibration of the Quality of Connections Survey (QoC) ODI, should be retained as a financial, rather than a reputational only incentive. Having considered Ofgem's feedback (comment and research within annex 8.1), we continue to believe it is essential that the QoC ODI milestones are financially incentivised, ensuring TOs retain the necessary focus for customer connections, given the fundamental impact they will have in achieving Net Zero targets. This is the only remaining financial incentive for stakeholder engagement and customer service in RIIO-T3, a behaviour where the financial incentive has diminished from RIIO-T1[196] (0% in RIIO-T3). Despite the criticality of the commercial and design elements of the customer connections service during connections reform which the government have noted as essential to achieving CP2030.

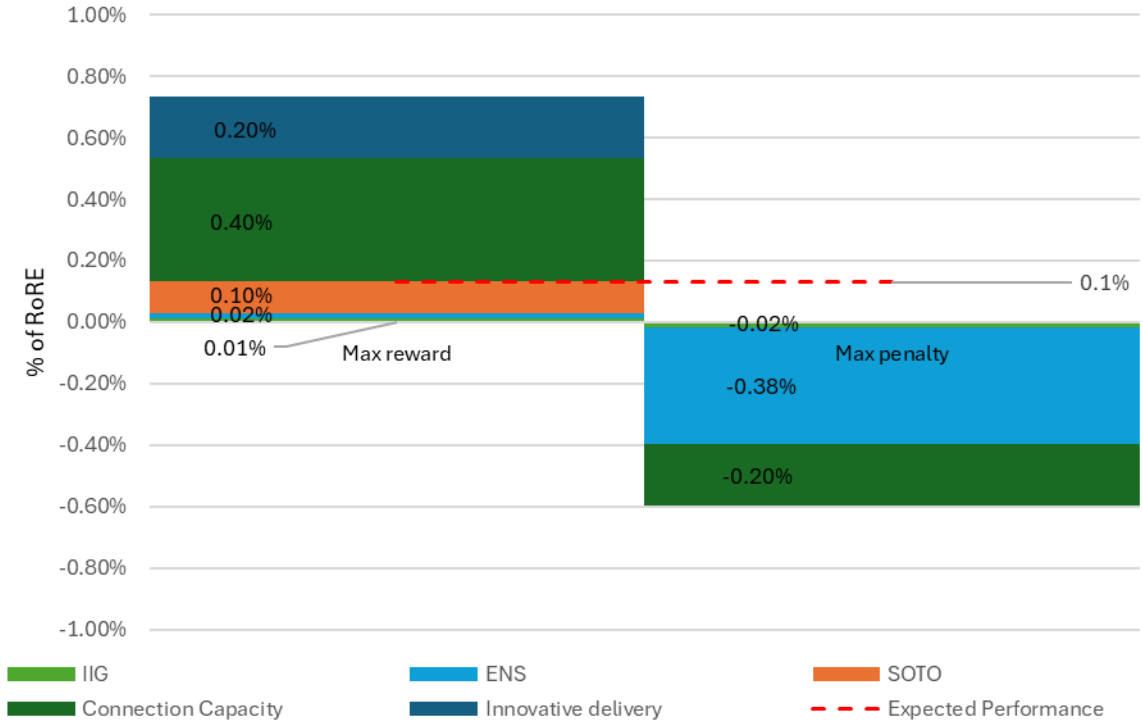
b) Are the ODI targets challenging yet achievable?

5.1.9 Since submitting our business plan, we've provided evidence that the RIIO-T3 package, in comparison to RIIO-T2 and other comparable utility sectors, such as water, was increasing in asymmetry with rising penalties[197]. Ofgem's DD outlines a proposed package that appears to provide greater symmetry as outlined below in Figure 5-1. Yet, there remain many uncertainties, the setting of targets lacks clarity and the volume of assumptions within our bottom-up analysis demonstrates that this policy intent, in practice, has not been executed in the detail of target setting and incentive calibration from Ofgem:

- At this advanced stage of the price control development, the ODI package and methodology is not yet finalised. Our analysis is based on assumptions creating a level of uncertainty for each individual ODI – including ODIs which are well established from RIIO-T2 and RIIO-T1.
- Figure 5-1 shows that the proposed maximum rewards of RoRE% from Ofgem's DD is unachievable. Our likely forecast (the red line), based on a number of uncertainties shows it's more likely to be around **0.1%** of RoRE (£4.7m) as outlined in Figure 5-1 below[198]. *Note that this position does not consider the impact of the TIM and ASTI, this is considered in Chapter 1 FQ17- the conclusion of which notes that the 200bps outlined in Ofgem's DD is unachievable.*
- This demonstrates that there is less incentive opportunity from RIIO-T3 than in the previous price controls. This does not align with Ofgem's RIIO-3 impact assessment which notes the incentive package does account for the scale and increase in TOTEX[199].

[195] https://assets.publishing.service.gov.uk/media/64c8e96e19f5622360f3c0f0/electricity-networks-commissioner-letter-to-desnz-secretary.pdf Specifically recommendations 7 and 12
[196] https://www.ofgem.gov.uk/sites/default/files/docs/2012/04/sptshetlfp_0.pdf
[197] Please see SPT and Ofgem Bi-lateral Material Jan-May 2025
[198] The assumptions made: IIG: T2 average performance applied to T3 Incentive, ENS: T2 Average performance applied to T3 incentive on £25k VoLL, SOTO: T2 average performance, Connection capacity: £0 as assuming on time delivery, Innovation: based on Distribution Incentive actual reward as a % of max reward then applying the same % to our max reward.
[199] https://www.ofgem.gov.uk/sites/default/files/2025-06/RIIO-3-Draft-Determinations-Impact-Assessment.pdf Ofgem's RIIO-3 Impact Assessment page 10 and 18

Figure 5-1 – RIIO-T3 Incentive Package (with TIM) – Excluding ASTI



Clear asks to Ofgem to deliver the policy intent from DDs

5.1.10 Table 5-1 outlines a summary of the key asks evidenced by our bottom up analysis – these are explained in detail in each of the individual questions.

Table 5-1 - ODIs, Impact Assessment by SPT and Requests from FD

Name	DD Max reward	DD Max Penalty	DD impact	SPT Ask for FDs
Innovative Delivery* ***new for RIIO-T3***	0.5-1.00% RoRE	N/A	We welcome the consultation on the innovative delivery incentive, we aim to work with Ofgem on the details of this incentive. However, there is a high level of uncertainty due to the lack of detail and likely subjectivity.	• To increase the objectivity of the innovative incentive SPT propose an annual report and incentive alongside a diverse panel assessment with specific categories with a scoring system. • Expanding 'NESO engagement' to 'Stakeholder engagement' to consider Environmental (carbon savings, biodiversity and nature enhancements), + Stakeholders ("Innovations to facilitate community acceptance/support"), + "Innovations in design/engineering" could be extended to include not only assessment of the "use of new technologies that reduce cost or engineering approaches that achieve long-term value". • The current bar set by Ofgem to demonstrate £10m of consumer benefit without any methodology creates uncertainty as to the likelihood of achieving reward.
CSNP-F* ***new for RIIO-T3***	10% forecasted totex of project	5% forecasted totex of project	The CSNP-F's scope and Target Delivery Date (TDD) setting is highly uncertain. This has made the impact unquantifiable for RIIO-T3. We support Ofgem's proposed policy positions on date 'deadband' and 'lump sum' payments but further certainty of calibration is required.	• Clear definition required for projects which will have the CSNP-F apply. We propose this is for '*wider works'* rather than 'enabling works' which will fall within the Connections Capacity incentive. • That the TDD is set on a P50 basis with independent assessment from the NESO and/or ITA at cost assessment stage of the project. Delay events are retained and comparable to the ASTI framework. • ***Further calibration of reward and penalty required.***
Connection Capacity ***new for RIIO-T3***	0.4%	0.2%	We're supportive of Ofgem's Option 1 '*connections capacity incentive'*. However, this sees on time project delivery extended to smaller projects.	• Given the increased risk in connections capacity we proposed that this be initially a reward only incentive following precedent from the introduction of the Quality of Connections Survey (QoC) in RIIO-T2. • Delay events, equivalent to CSNP-F should also apply. The same policy principles applied to CSNP-F with 'lump sum' approach for on time delivery alongside deadbands should apply. This should be measured in MVA to account for the connection of operability projects.
Energy Not Supplied (ENS)	0.02%	0.38% RoRE	We're supportive of the retention of ENS given the importance of resilience of the network as we move towards a greater reliance	• RIIO-T3 is becoming heavily weighted towards penalty – in order to re-calibrate for RIIO-T3 to provide similar opportunity as previous price controls we propose to support Ofgem's methodology 1 which recognises the challenges of RIIO-T3 whilst setting an ambitious target. • The new stepped TIM dramatically reduces the potential for reward in this incentive – we propose the TIM is removed from the calculation.

			on electricity and network growth. Targets remain increasingly challenging. Target is uncertain due to unknown VoLL figure.	• Finalise the VoLL figure in line with ENA working group ahead of FDs, considering the impact of this in the overall ODI package.
Interruption and Insulation Gas (IIG)	*Reward/Penalty calculated by applying the value of CO2 equivalent, for every ton over or below the target. No CAP/Col*		We support the approach on setting targets based on SBT – a challenging target for TOs. We do not support an arbitrary 5% threshold for exceptional events, this will create inconsistency amongst TOs.	• [redacted] Ofgem set a financial level or volume for exceptional events for all TOs reflecting a common environmental impact. • The new stepped TIM dramatically reduces the potential for reward in this incentive – we propose the TIM is removed from the calculation.
System Operator - Transmission Owner	No cap	N/A	We support the retention of the SO:TO incentive for RIIO-T3 given the increasing importance of system access for CP2030.	A clear definition of "system wide" must be agreed before progressing with the application of different percentage reward for SO:TO projects. The clawback mechanism is inappropriate given the SPT behaviour for STC-P 11:4 requests.
Quality of Connections (QoC)	Reputational only	Reputational only	We support the retention of the QoC however we're disappointed at the most critical time for connections offers, in connections reform this is being removed as a financial incentive.	Retain the Quality of Connections incentive as a financial incentive, to ensure TOs continue to focus on not only connecting key projects to achieve net zero but reduce delays, improve the customer end to end journey, increase transparency and drive efficiency in TO process.

5.1.11 We believe we can work with Ofgem until FD to deliver a package of incentives for RIIO-T3 that encourage the TO behaviours needed to meet CP2030, with challenging yet achievable targets – delivering consumer value and accelerated economic growth. The consequences of non-delivery impacts the financeability of the full package of RIIO-T3 and risks behaviours and incentives being diluted to the detriment of consumers.

INCENTIVES QUESTIONS

FQ 33 Do you agree with the proposal for how we will set ODI caps and collars at final determinations that are fixed for the duration of RIIO-3?
As noted above in our chapter 5 response, there are a number of policy developments ongoing and no set targets therefore it is not possible to forecast the over impact of the cap and collars across the price control.

Given the scale of network growth in RIIO-T3, we support Ofgem positions that ODI RoRE should be set on the ex ante base revenue, so incentive strength remains throughout the price control (i.e. caps and collars not fixed):

For each of the individual ODIs:

- We disagree with the **CSNP**-F having a 'double cap' for reward, of 10% of project costs and 30% of forecasted constraints costs – this means that the 10% reward is artificial and unachievable. This makes it complicated and uncertain in any forecasting for this ODI. We do agree with the asymmetry of this ODI and 5% penalty cap given the overall uncertainty of this ODI's application (including scope) in RIIO-T3 and future price controls. We also do not consider it appropriate to have an alternative rewards and penalty calibration for non-CSNP projects- the ODI-F should have a clear scope and calibration across all applicable projects.
- The **connections capacity ODI's** calibration and target setting is unknown, given this uncertainty and the industry change via connections reform, we believe this ODI should be reward only for the first two years of RIIO-T3 in order to test its application. This follows precedent set in RIIO-T2 on Quality of Connections which was initially reward only.
- We're supportive of the cap and collars applied to existing RIIO-T2 ODIs (ENS and IIG).
- We support there being no cap on the **SO:TO** ODI given the importance of system access in delivering CP2030

ETQ 1 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?
SPEN considers it an inappropriate approach to apply the CSNP-F ODI-F to additional projects, including those submitted through the Load Re-opener (LR). Paragraph 4.53 of the consultation on LR confirms that for projects submitted via the LR "*Given the importance of delivery for these projects, we propose to include a LO for delivery of the Load Re-opener outputs on the given delivery date*".

The criteria for assessing if the CSNP-F ODI-F should be more widely applied in the consultation lacks clarity, fails to take into account relevant factors and makes no reference to the risk of double jeopardy or reward for the same delay or early delivery. The DD ET annex states that one of the key reasons for inclusion of an LR project would be "*if it is required to enable key CSNP-F Outputs*". However, this is already being achieved - as a TO we would be incentivised / penalised for delivery of an associated CSNP project and given the assessment criteria suggested, already indirectly incentivised to deliver the LR project. The proposal suggests that the TDD will also be reviewed as part of a CSNP-F ODI-F application, however, if the project under consideration is connected or associated by a CSNP project, the TDD will be driven by the project.

We would ask Ofgem to consider which additional criteria may apply and against which a project could be assessed. We would propose **any enabling works and connection works schemes are excluded** from the CSNP-F as they will likely be included in the connections capacity ODI. This will avoid any double counting. We also think this will keep TOs focussed on delivering works in the CSNP-F which will deliver the most value. We would therefore welcome the opportunity to work with Ofgem in setting the rationale and conditions for extending the CSNP-F ODI beyond identified CSNP projects.

The proposal to extend the application of the CSNP-F ODI-F to additional projects makes us question the rationale, why do we have two separate funding mechanisms which have essentially the same regulatory process. It appears to SPEN that the current methodology, ie: allocating CSNP-F ODI-F to non CSNP projects, that non CSNP projects for ITA scrutiny, duplicates the LR track 1, and this should be considered further by Ofgem.

Whilst we recognise that Ofgem will review each project on a "case by case basis" (para 3.11) and consult on the decision prior to a licence modification (para 3.14), we question the application of the CSNP-F ODI-F to non CSNP projects, given it will raise the regulatory burden at a period of intense development. Furthermore, there is no proposed approach to setting output or target delivery dates (TDD) for LR projects and we ask Ofgem to consider the consumer interest in the allocation of projects, which will be low and consultation engagement poor, resulting in unnecessary bureaucracy (essentially a document exchange between Ofgem and the respective TO) when the focus should be on project progression and delivery.

We also consider the LO applied to LR projects, inappropriate given this increasing the overall regulatory risk of TOs with uncertainty over application of the ODI. For reward but certainty of penalty under enforcement action, this application seems unreasonable and does not align with the asymmetric policy intent applied to the CSNP-F for CSNP projects. We do not believe this was considered in Ofgem's impact assessment.

ETQ 2 Do you agree with our proposed approaches to determining a TDD for CSNP-F Outputs and non-CSNP-F Outputs?

Impact Assessment for CSNP-F: We recognise that delivery incentives for major projects have a role to play in the regulatory framework. However, as per our response to the SSMC, to date, there has been no financeability nor investability assessment completed for the current ASTI ODIs, which includes potentially very significant penalties across the set of ASTI projects. We have seen no evidence that the impact of ASTI nor the uncertainty of date setting has been taken into account in the RIIO-T3 DD impact assessment.

We support the principle of aligning delivery incentives with consumer value. However, we have significant concerns about the uncertain policy position of how Ofgem will set the TDD:

- **At this advanced stage of the price control we have seen no lessons learned from ASTI- a mechanism which is still in flight and no rewards or penalties have yet been established, despite consistently asking for this throughout WGs.**
- It is unclear where roles and responsibilities sit with setting the TDD between the NESO and Ofgem. With the NESO failing to attend a meeting in regards to the CSNP-F. It is unclear what terms and definitions are being used – Ofgem introduced new terms on behalf of the NESO which were inconsistent with published Ofgem consultation on: RIIO-T3 DD, RIIO-T3 informal Licence Consultation[200] and CSNP Guidance[201]. This caused confusion amongst key stakeholders in attendance of the meeting but is also opaque to wider industry stakeholder responding to these consultations.

Proposal for FD:

- We have seen no consideration from our consistent policy position that the TDD should be set following project assessment, following competitive tender, this should be set using the P50 date. This would provide methodology and science to the TDD Setting and consistency across TOs. This was not available at the time of ASTI – as referenced in Ofgem's decision (2022) section 7.38.
- Ofgem's updated communication[202] outlines that the TDD will be the 'Recommended Delivery Date' date from the CSNP taking into account the consumer benefit and deliverability. This will not be the ODD as stated in previous publications.
- It remains unclear the roles and responsibilities between NESO, Ofgem and the TOs in setting the TDD, we strongly reject that the Recommended Delivery Date from the NESO should be the date inserted in the CSNP-F re-opener without any impact assessment or consultation with TOs. As expressed in previous cross TO Ofgem WGs we feel strongly that TO input is required in setting delivery dates given our experience of procurement, delivery and asset energisation, this will be based on consistent QSRA. We welcome further engagement with NESO and Ofgem to establish this process, as outlined in the NESO's presentation pack 'CSNP: Project in service Dates' (12 August 2025).

[200] https://www.ofgem.gov.uk/consultation/riio-3-initial-licence-consultation
[201] https://www.ofgem.gov.uk/consultation/draft-centralised-strategic-network-plan-guidance
[202] Email dated 14.8.2025 'RE: ET3 Group ODI Discussion'

- To reduce the number of applications for the amendment of dates, delay event claims and associated consultations, which detract from both TO and Ofgem resource we believe that including TOs to agree delivery dates for the CSNP-F re-opener condition at the cost assessment stage will be more efficient. We welcome working with Ofgem, TOs and the NESO with a focussed task force to finalise this position prior to FDs.
- As noted above we propose the TDD is set at the cost assessment stage or re-assessed following competitive tender and set on a P50 basis following QSRA.
- **This approach would ensure that the ODI-F is calibrated in a fair, symmetrical, and deliverable manner.**
- **ODI calibration:** Given the uncertainty at this point in the price control we welcome the 12-month deadband. For other points in relation to ODI calibration please see response to ETQ5.
- The scope and application of the CSNP-F is covered in response to ETQ1.

ETQ 3 Do you agree with our proposed inclusion of a minimum availability standard in the CSNP-F ODI-F?
The proposed **93% Minimum Availability threshold** is overly stringent, particularly for **new infrastructure** that may face early-life operational issues or be located in **challenging environments**. Ofgem clarified that 93% was based on the lowest average annual system availability for the TOs as in the 2023-24 National Electricity System Report. Annual average system availability is based on the existing asset base and does not consider the risks and performance specifically associated with new assets and should not be used for the purposes of Minimum Availability threshold.

Application of the availability standard must be proportionate and, based on factors such as asset type, location and operational complexity as well as the timing of energisation e.g. in the context of the status of the surrounding/ wider system and its ability to support asset operation. The Minimum Availability standard is untested for the ASTI portfolio and no % has been set. A joint TO proposal on how the minimum availability standard should be assessed is currently being developed. We propose to form a workstream to develop and finalise the framework for Minimum Availability Assessment to ensure that the approach is aligned across all TOs.

ETQ 4 Do you agree with our proposed approach to Delay Events in the CSNP-F ODI-F?

We are deeply concerned and strongly oppose the blanket exclusion of supply chain issues from the list of acceptable Delay Events. In our view this is overly punitive, especially in a global context of constrained manufacturing and logistics, including but not limited to HVDC equipment.

The Delay Event test is whether an event “outside of the TOs’ control that causes or is reasonably expected to cause a project to be delayed by at least 30 days...”. Ofgem applying a blanket rule “not to allow Delay Events that are related to the supply chain” would amount to a fettering of its discretion and misapplication of this test - each case must be considered on its own facts based on the Delay Event test.

We recognise that the Advanced Procurement Mechanism (the APM) is intended to serve as a tool to mitigate the supply chain issue however it is impossible to guarantee the efficacy of the APM until this is tried and tested. TOs may face unavoidable delays despite proactive mitigation and there may be scenarios where supply chain constraints cannot be addressed even when there is early funding available. We are actively engaging with the supply chain to use the APM, however we have not yet gone out to market for all cost categories available under the APM, therefore we do not have market tested delivery dates for all asset types and supply chain constraints may be an issue for assets not yet tendered. **In these instances, we strongly advocate for conditional exclusions where there is clear evidence that it is outside of the control of the TO.**

Should Ofgem not consider the inclusion of similar non-exhaustive list of exemption events as per Delay Events within the ASTI framework, this should be accounted within the methodology the TDD. It is also imperative to account for project maturity at the time of TDD set up. See response to ETQ1 above.

ETQ 5 Do you agree with our proposed shape and size of the CSNP-F ODI-F incentive?
We welcome Ofgem’s proposed changes to the CSNP-F ODI Incentive:

- The lump sum provides additional incentive to deliver on time rather than the reward diminishing towards the TDD – we would encourage a stronger incentive rate at 5% rather than 2.5% - this would provide stronger incentive to hit government CP2030 targets. We welcome the max reward of 10% of project costs vs penalty of 5%- we agree with Ofgem that there is a need for a strong incentive and given the scale of challenges presented it is essential the likelihood of penalty over reward is considered. However this does not negate the need for delay events outside the reasonable control of TOs, as noted in response to ETQ 4.
- The approach of a 'deadband' as per response above, there is no clear policy or precedent from Ofgem to set the TDD. We welcome this acknowledgment from Ofgem; however the deadband does not negate the need for a clear process and methodology to set the TDD going forward. Ofgem must also ensure the licence obligation that licence breach will not 'kick in' until penalties apply following the deadband.
- We disagree with Ofgem that the delay events should be used to move the penalty only date, if there are circumstance outside the reasonable control of the TO, including scope changes, the date should then be-reset and there still be an opportunity for reward.
- See ETQ1 for application and scope of CSNP-F. See FQ 33 for reference to the cap and collar applied to CSNP-F.

ETQ 6 Which of the two proposals for the Connections Capacity ODI-F target setting methodology do you think is most appropriate and why?

Option 1

Like Ofgem, Option 1 "Measures TO performance in connecting the generation projects prescribed in the newly reformed connections queue" is our preferred proposal. We are supportive of a connections capacity incentive and feel that its close association with CP2030 is appropriate, given its significance on the path to net zero. Once the Gate Two to Whole Queue (G2TWQ) process is complete, this will allow a clear delivery pathway to be confirmed for each TO, allowing an initial baseline to be set for the remainder of the RIIO-T3 period.

We agree that performance can be monitored using the RRP, however, given the challenges highlighted[203] below we would propose an end of period assessment is more appropriate, than an annual assessment. The proposal is a clear delivery incentive for CP2030, strongly aligned to strategic goals and our Business Plan. Option 1 allows measurement which is in consumers' interests as well as supporting Government's ambitions. We strongly believe that the design of such an incentive must focus on aspects within TOs' control and reflective of customer requirements.

- There is a caveat, the proposal is based on the successful outcome of the G2TWQ process in reforming the existing Connections Queue. This G2TWQ process needs to set a clear and robust new queue which will allow a clear delivery pathway to be confirmed for each TO, allowing an initial baseline to be set for this Connections Capacity ODI-F for the remainder of the RIIO-T3 period. Upon the conclusion of G2TWQ exercise, each project will have a "delivery date" within their updated connections contract. Ofgem should use this to set a target for the number of CP2030 projects each TO has with a delivery date within the RIIO-ET3 price control period. Ofgem's proposal is that success is based on the cumulative number of projects completed by their 'target date'. It is worth noting that this ODI-F incentive, and in particular the baseline and targets, cannot be finalised until this G2TWQ exercise has been completed, by which point the RIIO-ET3 period will have commenced. We therefore envisage year 1 of the RIIO-ET3 as baseline setting, with the incentive operational in years 2-5.
- Whilst SPEN have a preference for Option 1, we do have some suggestions and questions with the initial proposal, which Ofgem should address when reviewing the design of the ODI. We stand ready to support Ofgem with the more detailed development of this ODI.

Contractual Connection Date

- We seek confirmation from Ofgem that the proposed "target" date is each project's contractual connection date as this is not implicit within the DD document. We believe each project's

[203] Ofgem led Connections Incentive WG 23.07.25

contractual connection date is the appropriate measure for setting this ODI baseline. If this is not the case, clarity on the target setting methodology is required for a review of the proposal in full.

- Current contractual connections' dates in connection offers are formulated by us and will be subject to review as part of the connections reform G2TWQ process. The approach proposed by Ofgem in Option 1 must therefore complement this important industry-wide exercise, with any baseline being developed after this exercise has been completed, given this industry change we propose Y1 is reward only as outlined in FQ33. It is also worth noting that we would require this position to be revisited if the NESO methodology on "advancing" projects meant changing our allocated dates.

Factors outside of TO control

We strongly believe that the design of such an incentive must focus on aspects within TOs' control and reflective of business requirements. The ODI baseline "target" must allow TOs the opportunity to adjust the "target" when there are factors present outside licensees' control such as customers changing their connection characteristics or requesting an extension to their contractual connection dates, given a 'timely' connection is equally dependent on the customer delivering their project to agreed programme timelines.

We proposed alignment with ASTI (and CSNP-F) delay events: Other factors outside of the TOs control include delays to planning decisions from the relevant planning authorities, landowner / agent negotiations, pre-commencement environmental conditions (for example, tree felling is required but the commencement dates fall within the bird nesting season) and unforeseen delays (for example, equipment stolen from site, delivery of faulty equipment) or supply chain constraints. These are other factors outside of the TOs' control, although not exhaustive, which would require for the "target" baseline to be re-set.

Whilst we recognise the inclusion of the APM in RIIO-T3 we refute that this will "fix" all possible supply chain issues (see response to ETQ25) in the RIIO-T3 period and supply chain and service contract specialist constraints remain.

Furthermore, the lead times for planning and land continue to be an additional challenge. G2TWQ projects and connections date offers are built on standard timescales for land and planning, any decisions which fall outside of 'standard' timescales are therefore potentially a risk.

ODI measurement

We agree that performance can be monitored using the annual RRP exercise, however, given the likelihood of customer projects moving across years within the price control, we believe this ODI should be measured at the end of the RIIO-T3 price control period, rather than on an annual basis. Whilst we consider the proposal option is directly measurable and transparent, we do believe it should be a cumulative capacity measure in MVA of Connection Entry Capacity, of CP2030 projects successfully connected, rather than simply a count of connecting projects. OAs part of the connections reform exercise, NESO may redistribute the CP2030 regional capacity allocations to reduce or increase supply in our area following queue formation. In the event of this occurring, we would want to work with Ofgem to recalibrate the incentive target, reflecting the changes which the NESO has made to regional allocations. We are seeking clarity on whether the incentive only measures the delivery of CP2030 projects which align with CP2030 regional technology allocations, or if the proposal also includes the connection of over-subscribed projects, across these regional technology pots, who are also guaranteed a Gate 2 offer, as they have secured planning consent. Given the already extremely ambitious nature of the CP2030 plans, we would suggest that the timely connection of projects above the CP2030 threshold must always be considered as a reward, given our best view aims to deliver above our CP2030 regional allocations. We welcome Ofgem's recognition of the challenging nature of the incentive proposal given ongoing connections reform and the ambition of the CP2030 timelines. The balance of reward and penalty will incentivise TO performance, to innovate and invest in resources and processes, with a view to maximising consumer benefit in the delivery of timely and efficient connections. As noted above in FQ33 we consider an initial period of the ODI-F being reward only to be appropriate. In the event of a cumulative target, we would propose that a sliding scale for reward/penalties should be considered given the extremely ambitious proposals for delivering on the various CP2030 technology pots. A realistic scalable reward scheme would include a deadband where zero reward or penalty would be awarded, and similar for failing to meet the targets. This would incentivise TOs to push every project to timely completion to ensure the maximum possible capacity is available to consumers. We request that the details for this proposal are explicitly clarified and agreed in the Ofgem working groups going forward for

consideration prior to FD. ONESO may redistribute the CP2030 regional capacity allocations to reduce or increase supply in our area following queue formation. In the event of this occurring, the incentive target must be recalibrated, recognising it should be challenging but achievable. We are seeking clarity on whether the incentive only measures the delivery of CP2030 projects which align with CP2030 regional technology allocations, or if the proposal also includes the connection of over-subscribed projects, across these regional technology allocations, who are also guaranteed a Gate 2 offer, as they have secured planning consent. Given the already extremely ambitious nature of the CP2030 plans, we would suggest that the timely connection of projects above the CP2030 threshold must always be considered as a reward, given we will be delivering above SPT's CP2030 targets. We would urge Ofgem to ensure that the incentive will work in the event of the following scenarios (which are not currently catered for): Modification applications: A customer asks for a delay via the formal modification application process. The incentive design must allow for TOs to flex delivery to meet customer requests and calibrated to avoid TOs being penalised for project delay as a result of customer change.

- Customer connection delay: The incentive design must recognise circumstances when a TO is ready by the target date, but the customer or third-party is not. We would expect to be rewarded under the ODI design if we could evidence our readiness to connect. Evidence submitted may include: a letter from NESO to confirm the TO part of the connection work was complete, evidence from the commissioning panel meeting204 showing works have been commissioned, a summary of physical work that cannot be completed until the customer has completed its works.

Our ask to Ofgem would be:

- a mechanism within the incentive for TOs to review and update the 'target' date based on externalities outside TO control for scenarios outlined above, including but not solely limited to customers requesting a delay to their contracted connection date.
- the calculation of the incentive target is cumulative and should be measured in MVA to account for the connection of operability projects.
- a cumulative capacity target with reporting at the end of the period, which takes account of connecting demand and generation projects rather than a connections project count and annual reporting which will be challenging giving the movement of projects.

Option 2

SPEN have considered Option 2 but do not consider that this is appropriate. Option 2 to "Measure the added capacity, in MW, to the ET network each year by delivered projects funded in RIIO-ET3" could incentivise infrastructure solutions which are not aligned with customer requirements. The focus must be on the most appropriate or cost-effective solution for consumers. For example, in advance of any project we may actively explore flexibility solutions alongside optionality of building additional network infrastructure.

We would also caution that it is very difficult to accurately define network capacity in an interconnected transmission network and would the incentive take account of calculations of additional capacity within TO control or via connecting third parties. This means under Option 2 it would be challenging to set annual baselines to allow for projects, and the incentive would have a moving target. We believe Option 1, where additional capacity is measured on a project-by-project basis is a more accurate measure.

We also believe that there is a risk of double reward/penalty scenarios with a focus on increasing network capacity, which is similar in scope to other proposed incentives in RIIO-T3, such as the ASTI mechanism and CSNP-F.

We attended an Ofgem led Connections Incentive workgroup on Tuesday 19 August, at which additional incentive development was presented on option 1 (proposed measurement / incentive value), a summary of option 2, plus a NGET incentive proposal. This information has not been considered in full and is not reflected in our DD response. We look forward to engaging with Ofgem further to finalise the ODI ahead of FD.

204 OCC SCADA, OPSAF documentation.

ETQ 7 Do you have any further considerations on our chosen direction for a RIIO-ET3 Connections Capacity ODI-F, including detail on how the targets could be built up?
In addition to our comments and response to ETQ 6 above, we would urge Ofgem to set targets which are directly related to the Transmission Entry Capacity, that the calculation of the incentive target is a cumulative total and should be measured in MVA to account for the connection of operability projects. Targets based on the capacity metric are important given the consumer benefit or detriment is more strongly related to the capacity of generation connecting or failing to connect than by the count of connections. Falling short by one 50MW connection does not have the same effect on consumers as by a single 500MW connection, the impact on consumer value must be considered in the ODI's calibration.

ETQ 10 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?
The SO:TO ODI-F has an operational focus with a specific behaviour focussed on reducing outage times to improve system access, between the operating parts of SPEN and the NESO, teams working at the coal face of the network reviewing day to day challenges. We support the retention of the SO:TO ODI-F as it has operated in RIIO-2, with the proposed transition of activities to business as usual (BAU). The innovative actions we have taken during RIIO-2 have benefited customers by saving in excess of £110m. During a period of significant investment, it is understood by DESNZ, NESO and Ofgem, via the System Access Reform initiative that system access and outage planning remains one of the significant challenges of delivering CP2030. The behavioural focus of this ODI should be retained for CP2030. It would not be appropriate for losses to be considered and this has not been considered in the calibration of this ODI. This provides uncertainty around the scope of this ODI.

Given the calibration and scope of the innovative delivery ODI, losses does not align with the behaviour of the ODI-F. Losses are included in the environmental annual reporting, this is an ODI-R. Any financial ODI has not been consulted on in SSMC or included in Ofgem impact assessment for RIIO-T3.

ETQ 12 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 welcome the alignment of the IIG ODI-F target methodology with the TO's glide path to meet science-based targets as this is consistent with the methodology proposed by us. [redacted]
Ofgem should consider these factors in RIIO-T3's FD to ensure fairness across the TO's ODI application to ensure a level playing field.

ETQ 13 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 are surprised that Ofgem has not sought views on the 5% threshold proposed before an IIG exceptional event can be claimed. This was not discussed with the TOs during the consultation period on the IIG-ODI prior to DD and therefore the basis appears to be an exceptional event submitted by SHET, subsequently rejected, for a very small gas loss. The SHET event is not representative of the potential financial impact for other TO's and therefore setting this figure of 5% of previous years leakage, before an exceptional event can be claimed, to reduce regulatory burden is not appropriate. We have therefore chosen to address this issue in response to this question along with the treatment of historical inventory.

Exceptional Event:
In RIIO-T2 an IIG exceptional event can only be claimed if it could be demonstrated the cost of providing a submission was less than the impact of the associated leakage on the IIG incentive mechanism. This definition was at best vague as the cost to the TOs to create a submission is relatively low compared to the non-traded carbon price set out in the Green Book Supplementary Guidance. We believe the setting of an arbitrary 5% of previous year's leakage does not treat the TOs in a fair manner and it would be more appropriate to set a fixed financial materiality threshold before an exceptional event could be

claimed. The purpose of the exceptional event mechanism is to allow TOs to exclude from the incentive events that are beyond their reasonable control and they can prove they took all appropriate measures to prevent the event and the associated loss of gas. [redacted] This approach is inconsistent, holding the TOs to a different measure for events of which they have no control and likely excluding some TOs from being able to claim an exceptional event. Setting a fixed financial materiality threshold or gas volume would set a clearer measure when a TO can trigger an exceptional event. Ofgem need to be mindful that the intent of the IIG incentive is to encourage the TOs to address leaking assets and incentivise moving away from SF_6 gases where possible, not to penalise them for events not within their control.

Historical Inventory:
We find Ofgem's proposal regarding the use of the IIG Exceptional Event mechanism to manage historical IIG inventory data to be unclear. We presume the intent is if inventory discrepancies are greater than 5% previous year's emissions then at this point it could be considered. We do not think this measure is appropriate as the margin is too high but also it penalises the TOs for leakage that has not occurred. During discussions with Ofgem we have been clear that we believe any inventory adjustment should only be applicable to assets where the TO can evidence that there is not a history of leakage, i.e. no top up history, for an asset as far as records allow.

Ofgem have stated they believe the TOs have not been able to demonstrate how many assets this may affect or the significance of the data discrepancies. We have tried to discuss this subject with Ofgem on a number of occasions[205] however we have received very little feedback. It is disappointing that Ofgem did not engage further or request more information on inventory discrepancies before publishing their Draft Determination.

We have been fully transparent to Ofgem that the majority of our IIG inventory is based on data from name plates and from other reference points and not from direct measurements. This approach is consistent with ENA Engineering Methodology S38 Reporting of IIG Banks, Emissions and Recoveries. IIG assets are filled to give the appropriate gas density for the operation of the equipment. Because each component is individually manufactured, the name plate value at the point of manufacture is the recognised guide to the gas density content but is not an accurate measurement. It is clear from our IIG methodology statement how we calculate leakage from top ups and inventory discrepancies and we have demonstrated where we have found assets with inventory discrepancies and have reported as leaks in RIIO-T1 and RIIO-T2. We have previously discussed with Ofgem we do not regularly remove IIG from assets and therefore we cannot use service logs to reassess our IIG inventory. Using this methodology to provide an accurate inventory would require the gas to be removed and refilled on all assets.

As we move into an era of widespread removal of SF_6 from transmission networks the impact of inventory discrepancies becomes more significant when considered against the IIG incentive. In RIIO-T3 we have plans to significantly reduce our SF_6 inventory by asset removal and employing Gas Insulated Busbar (GIB) retrofill solutions. As previously communicated to Ofgem a relatively small, percentage wise, inventory discrepancy on GIB could account for a significant mass of gas and therefore potential penalty. The intent of the IIG incentive is to encourage the TOs to minimise the leakage of IIG, particularly SF_6. Allowing TOs to make inventory adjustments based on measured values compared to name plate values during disposal of gas, assuming it can be proven no leakage has occurred, is very low risk to Ofgem and it is not clear why they think this should not be allowed.

We believe inventory adjustment should be allowed up until the point where TOs stopped using name plate values to inform their IIG inventory, for us this would be into the RIIO-T1 price control period when accurate recording and monitoring of gas density was introduced. We propose Ofgem address this inventory issue, by allowing historical inventory adjustment's and not recording these as a loss. Inventory which has a name plate only recording, and a variance of SF6 is identified at the point of retro fill, are recorded but not attributed to the incentive losses, and that such adjustments are allowed until the point we stopped using the name plate method of recording gas density. We stopped using this method in the RIIO-T1 price control period, developing accurate recording and monitoring practice. In allowing adjustments of this type, Ofgem continue to incentivise us to take the right actions in reducing IIG on our

[205] SPEN-T/Ofgem Environmental Working Group Follow-Up email – 11/03/2025 / Slides shared with Ofgem post bi-lateral 12/09/2024

network, otherwise inaction could create a perverse incentive on TOs to avoid replacement if this will put them in penalty.

ETQ 14 What are your views on our consultation position for the SF6 Asset Intervention PCD in RIIO-ET3?

[redacted]

ETQ 15 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 the Ofgem methodological thinking on ENS targets and that Ofgem have anticipated and recognised the challenge to maintain current ENS standards of RIIO-2 given the enhanced work required in RIIO-T3. Methodology 2 produces targets for RIIO-T3 which we see are reasonable, given recent performance but recognise the challenging future position. Targets under methodology 2 are enhanced on those in RIIO-T2, challenging us to maintain our performance, but retain the penalty where just one event could create significant penalty.

In wider consideration of the ENS ODI-F, we ask Ofgem to consider:

- **the power of the ENS incentive**. In order to qualitatively assess the incentive we require an up to date Volume of Lost Load (VoLL) figure. As this is yet to be finalised, we are currently working on assumptions to calibrate the incentive. The uncertainty of the VoLL figure, combined with the reduction of the target, restricts the plus side of the ODI, creating an incentive with much higher risk, larger penalty and lower opportunity for reward given the strengthening target and calculation of the upside.
- **self policing for ENS events.** We are not proposing that unexpected and exceptional events should change, but that a materiality threshold[206] could be set below which we report via the RRP or an audit at close out. Such an action would reduce the regulatory burden for TOs and Ofgem at a time of increased industry activity. Reporting at close out or annually would ease the administration reporting load at the time of the event, during a period of operational pressure and retain the declaration and providing evidence as currently presented but on an annual basis. This development for transmission would reflect the approach taken in RIIO-ED2 licences, which defines "*Excluded and Exceptional Events".*

  Such a change in event reporting would increase operational efficiency and reduce administrative burden. We recognise that the customer number impact numbers and calculation of customer lost minutes is not transferable to TOs given the different dependency on DNO network set up, but an appropriate materiality threshold could be agreed.

ETQ 16 What are your views on our consultation position for the SO:TO incentive approach to BAU enhanced services in ET3?

SPEN welcome Ofgem's proposed approach to the SO:TO incentive for Business-As-Usual (BAU) enhanced services as outlined in the RIIO-3 Draft Determination. SPEN agree that the incentive framework, including the decision tree presented in Figure 3 of the Electricity Transmission Annex, provides a fair and transparent mechanism for distinguishing which activities fall under the incentive and which should be incentivised. This clarity is essential for ensuring consistent application and alignment across TOs and the System Operator.

Whilst not explicit within the DD publication we would expect Ofgem to continue to scrutinise claims made under the incentive and utilise the decision tree in their assessment to ensure it is being correctly applied across all TOs.

[206] RIIO-ED3 has a 3 minute materiality threshold applicable to DNOs on the equivalent incentive (CI/CML)

However, while Ofgem states in paragraph 3.211 that there is no need to amend the Network Access Policy (NAP) or STCP 11-4 process, SPEN suggests that Section 5 of the NAP should be updated to incorporate the decision tree from Figure 3. Embedding this framework within the NAP would enhance transparency and ensure that all parties have a shared understanding of the criteria used to assess enhanced services under the incentive.

ETQ 17 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 do not agree with the proposal to introduce a clawback mechanism; the idea suggests that as a TO we would not support or implement a STCP 11-4 request. We would only reject or fail to implement a NESO request for reasons:

a) the timeframe in which the request was made was impractical, due to the practicalities of implementation
b) the length of time required to consider and implement the programme challenge was insufficient,
c) the request was not technically possible, i.e. the existing asset base wouldn't allow the action.

If the proposed clawback was progressed it would need to adjust to allow TOs to submit reasons for non-implementation for Ofgem consideration, adding increased regulatory burden. Given the essence of the SO:TO incentive, to enhance SO:TO optimisation, reduce customer costs and improve system reliability there is no reason why a TO should reject a NESO request given the incentive mechanism as it is currently designed. Any rejection by a TO would need to be reviewed by Ofgem for inefficiency and non-compliance, increasing the administrative burden.

The proposition of clawback suggests that the NESO regularly presents ideas which is not reflective of the current regime. Given TO and NESO co-operation is proposed to be monitored via the new innovation incentive, this approach could encourage positive TO behaviour could be more beneficial than a clawback mechanism.

ETQ 18 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 have reviewed and assessed the three options proposed for managing differing approaches between TOs within the SO:TO ODI-F framework in the DD publication and recognise, Option 1 as the most effective and balanced.

As further explained above, SPEN supports Option 1, which proposes a differentiated incentive rate, 95:5 for enhanced services that are considered on a piece-meal basis and retaining the 90:10 rate for services that are system-wide. This approach acknowledges the varying scope and impact of TO contributions while maintaining a fair and consumer focussed incentive structure. However, for this option to be implemented effectively, a clear and consistent definitions of "piece-meal" versus "system-wide" services are essential. Without these definitions, there is a risk of misinterpretation and inconsistent application across TOs. How will the system effect be measured, in household affected, number of times the TO touches the system, a percentage of system affected?

SPEN does not support Option 2, which suggests rewarding TOs through the BPI for proactively planning whole-system enhanced services. This approach conflates long-term planning with the in-period flexibility and innovation that the SO:TO Optimisation Incentive is designed to reward. If Ofgem wishes to incentivise proactive planning, it should do so within the BPI framework in advance of BP submission, rather than replacing or diluting the purpose of the SO:TO incentive and looking retrospectively at a plan.

SPEN also disagrees with Option 3, which is inconsistent with other innovation style ODIs by introducing a competitive element among TOs to be the first to implement new ideas and technologies. This could undermine SO:TO collaboration and lead to unintended consequences, such as TOs working concurrently on a development and one being superseded by another and not rewarded. The SO:TO incentive should focus on reducing constraint costs and encouraging innovation that benefits the system as a whole, rather than fostering gaming that may hinder progress and dilute wider consumer benefit.

ETQ 19 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 are pleased to review the new Ofgem Innovative Delivery Incentive and are positive of its intention, recognising that there are opportunities for TOs to deliver in new and developing ways during RIIO-3 at a time where TOs are expected to deliver at an accelerated pace whilst innovating – an incentive in this area is most welcome. To support this response, an independent consultancy report Annex 8.2 was commissioned to outline regulatory best practice in panel assessments, this was a high level rapid assessment to help shape this initial consultation response, we look to work with Ofgem toward FD to develop the incentive further including clear guidance from the start of the RIIO-T3 period.

SPEN would support the expansion of the incentive to include the additional behaviour of: *Innovation in delivering carbon savings, biodiversity and nature enhancements* alongside expanding *'NESO collaboration' to be extended to cover all stakeholders including communities*. While the current pace of infrastructure development supports the UK's journey toward net zero it simultaneously contributes to the overall carbon footprint and ecological degradation. Balancing these dual impacts is essential to achieving meaningful, sustainable progress and we believe that by incentivising the behaviour there could be measurable consumer and environmental benefit.

In addition, we believe that the proposed behaviour "Innovations in design/engineering" could be extended to include not only assessment of the "use of new technologies that reduce cost or engineering approaches that achieve long-term value" but widened to include carbon or biodiversity savings also, given that the lowest cost solution isn't always the most environmental proposition. To support this extension a control which we would propose could be to relay actions back to the green book cost of carbon, thus quantifying the saving.

We also propose that 'NESO collaboration/engagement' is expanded to 'stakeholder engagement/collaboration' to encourage innovation and partnerships for environmental and community acceptance. The expansion to include a further behaviour of "Innovations to facilitate community acceptance/support" where review could assess any wider community impacts made by SPEN beyond bill reductions.

As industry leaders of critical national infrastructure, we play a critical role in delivering and advancing the UK's journey toward net zero, affecting all communities. We would urge Ofgem to consider our commitment to sustainability and stakeholders, whilst acknowledging and incentivising accordingly this is in line with Ofgem recent letter to the NESO and TOs in ensuring they engage with stakeholders transparently[207]. Delivering projects that prioritise carbon reduction, biodiversity and recognising the customers we serve is not only essential for long-term value, but also exemplifies SPENs role of leadership in responsible development.

ETQ 20 What are your views on our proposed design of the Innovative Delivery Incentive?
As noted above, in support of this response we commissioned a rapid independent assessment (Annex 8.2). This is based on the limited detail available from Ofgem's DD.

Our positivity towards the Innovative Delivery Incentive continues in our views on the proposed design. The panel assessment with the opportunity to submit evidence in advance supports a whole picture view of TO actions and demonstrations of change. The independent report commissioned look at best practice for undertaking panel assessment from different industries, including regulated industries. The recommendation was to set: "*standardised evaluation criteria and scoring rubrics and publish these well in advance, ideally before or very early in the first year of RIIO-T3. It should aim to incentivise behaviour changes from the beginning and because companies internally use predicted incentive performance in business cases, a late set of criteria may miss out on this.*" In terms of the panel membership, it is recommended that this is a diverse groups with SMEs for each incentive area from within and out with the electricity sector with peer review as required.

In reviewing the incentive, we seek further clarity on how it will work in practice, we welcome the panel assessment in 2028/29 and 2031/32 and would ask Ofgem to consider an **annual incentive alongside reporting** against set criteria to ensure TOs act appropriately throughout the price control period and not just as a panel assessment approaches. The independent report outlined support this by: *"A higher frequency of submissions and judging is better for developing expectations of what good looks like. Annual submissions, accompanied by detailed scoring feedback will drive excellence in behaviour*

[207] https://www.ofgem.gov.uk/transparency-document/public-consultation-and-engagement-infrastructure-build-letter-neso-and-transmission-owners (5 August 2025)

because it will rapidly become clear from the "past papers" what constitutes excellence. For this reason, feedback should be reasonably detailed and published for all TOs where practical. Ofgem will wish to consider the balance between confidentiality and driving performance over time." Annual reporting would show progression and TO commitment to innovation initiatives, increasing consumer value throughout RIIO-T3. We would go further and also support annual panel review of the incentive to ensure real tangible change, where we can demonstrate change implemented during the development stage of projects (in particular engaging with communities and stakeholders, and enhancing the natural environment) as well as project delivery (construction and on time delivery), showing innovative change in practice and allowing best practice to be shared amongst the TOs- creating a competitive edge.

The current bar set by Ofgem to demonstrate £10m of consumer benefit without a clear methodology creates uncertainty as to the likelihood of achieving reward. We would ask for a clear rationale for benefit, possibly set by region, as a percentage of turnover or investment giving a fair and consistent approach across the TOs of varying size and reach.

Although we would welcome a cap on reward of 1% of RoRE incentivising the business to take significant steps and implement innovative change to not only maximise potential reward but to provide measurable consumer benefit our bottom up analysis as outlined in Chapter 5 of this response shows that the likelihood of achieving the reward is low and the overarching ODI package for RIIO-T2 is unachievable. This was based on assumption of SPEN's distribution businesses performance in panels led by Ofgem. We are supportive of the innovative delivery panel however it remains, at this stage, subjective and the application uncertain. We urge Ofgem to continue engagement in development of this incentive and its overall strength in the total ODI package.

ETQ 70 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 welcome Ofgem's adoption of the regulatory policy and design from us (which should be recognised in BPI), however the evolved 'stepped' approach with greater focus on cost uncertainty and increased risk of material overspend in RIIO-T3 should not undermine but complement TIM's intended purpose of incentivising efficiency for TOs by setting out the sharing factors with customers. We view the risk management function under TIM is to deal with unknown risks that have not otherwise been identified and dealt with in the Price Control settlement and are materially beyond the TOs control (e.g. international prices volatility and supply chain constraints impacted by COVID, Ukraine war and other unforeseen global and geopolitical events). Further, we do not think TIM should be relied upon as a primary mechanism to deal with known risks, Ofgem should be setting appropriate ex-ante allowances or other funding mechanisms to target those specific areas (e.g. risk & contingency in capex projects, re-openers/UILOI for load/non-load schemes, and the unit rate in volume driver framework etc.).

ETQ 71 Do you agree with our proposed 'stepped' design of the RIIO-ET3 TIM, including the values that we have used to set each 'step'?
Yes, we strongly support the proposal to adopt a stepped TIM as being aligned with the proposed design from us in our Business Plan's 'RIIO-T3 Totex Incentive Mechanism Position Paper'.

Alongside this we note Ofgem's consideration of an asymmetric TIM (section 5.202 of the ET Annex) to drive TOs to deliver efficiencies for consumers. We have considered the potential for the asymmetric TIM and we would support this. As outlined in our policy position on the TIM, the reason we proposed the stepped approach was due to the current market prices being elastic and a high degree of cost uncertainty. These factors, more geared towards risk management, had a strong weight in our policy position development. However the TIM is a key driver for efficiency and as outlined in Chapter 1 (Finance) and Chapter 5 (Incentives), the incentive package presented in the RIIO-T3 DD from Ofgem, following our bottom up analysis, provides very little opportunity for outperformance and reward. An asymmetric TIM could provide further opportunity for outperformance in the full ODI package, encouraging TOs to deliver efficiency for consumers at a time of unprecedented investment scale. We welcome further engagement with Ofgem in the design of the TIM.

ETQ 72 Do you agree with our proposal to include ASTI within this TIM approach?
The ASTI framework is set based on the RIIO-T2 TIM, however there is flexibility to apply an alternative TIM (under the ASTI Guidance (4.75)) following engagement with Ofgem. We believe the stepped TIM

should be considered on a project by project basis through the existing ASTI framework and whether or not the stepped TIM should apply for those projects which have yet to have licence conditions drafted. The ASTI regime already has a +/- 5% mechanism, the TIM could be considered in addition to this and applied once the 5% cap is reached.

For those projects which already have licence conditions finalised and finance arrangements in place, the ASTI licence conditions should apply and changes to the design of mechanisms in RIIO-T3 should not be applied retrospectively.

Chapter 6 - Growth Mechanisms

6.1 Overview

6.1.1 RIIO-3 is unlike any previous regulatory cycle[208]. We've seen uncertainty mechanisms transform into network growth mechanisms through the development of ASTI, and we've seen unprecedented network investment unlocked by the HND and tCSNP2, replacing outdated Network Options Assessments that stalled decision making. During the RIIO-T2 period Growth mechanism have enabled the development of 25 Medium and Large Projects. Industry, the regulator and the NESO have worked together on these achievements, which have undoubtedly shaped and changed the way we have planned for the future in our RIIO-T3 Business Plan.

6.1.2 We had a clear ask of Ofgem for the RIIO-T3 growth mechanisms: *" …. streamlining of re-openers, automation where appropriate"* and *"Approving the accessible and flexible Advance Procurement pot alongside closing the gap for Early Construction Funding (ECF) for load related projects by increasing the % of pre-construction funding available to TOs to reflect Early Enabling Works and Strategic Land Purchase costs"*[209].

6.1.3 This section outlines:

- the impact RIIO-T3 growth mechanisms have on our Plan and CP2030
- asks of Ofgem to streamline and automate the growth mechanisms
- evidence from our bottom up analysis on pre-construction funding that will fund the early development of projects using growth mechanisms including strategic land purchase

6.2 RIIO-T3 growth mechanisms, our Plan and Clean Power 2030

6.2.1 We expect £7.5bn of our network growth in RIIO-T3 to be enabled by network growth mechanisms[210], ensuring we can meet the government's CP2030 targets and beyond – Table 6-1 below demonstrates the importance of the mechanisms, specifically the LR in enabling CP2030 (see column 5). The Use it Or Lose Pot and volume driver will be critical for enabling project implementation and the CSNP-F will enable projects required beyond CP2030 to meet the government's Net Zero targets. As outlined in our executive summary (Figures Exec-1 and Exec-2), the RIIO-T3 best view extend beyond the CP2030 projects.

Table 4-1 - Clean Power 2030 projects - Growth Mechanisms

Project code	Project Name	Current Delivery Date	TOs	Mechanism
BDUP	Beauly Denny 275kV circuit upgrade to 400kV operation	2030	SSEN, SPT	T3 Baseline
DNEU	Denny North 400/275 kV SGT2	2025	SPT	T2- VD
DLUP	Windyhill-Lambhill-Denny North 400kV Reinforcement	2029	SPT	LR
DWNO	Denny to Wishaw 400kV Reinforcement	2030	SPT	ASTI
DWUP	Kincardine - Wishaw 400 kV Reinforcement	2029	SPT	LR
EHRE	Elvanfoot - Harker OHL Conductor Replacement	2030	NGET, SPT	LR
LWUP	Kincardine North 400kV reinforcement	2029	SPT	LR

[208] Ofgem's DD overview document page 8
[209] This has been consistency communicating to Ofgem during bi-lateral from January—Aug 2025
[210] £3.016 bn will be delivered via T3 mechanisms, £4.46 via ASTI

TKUP	**East Coast Reinforcement Phase 2**	**2031**	**SSEN, SPT**	**ASTI**
VERE	**Strathaven to Elvanfoot OHL Conductor Replacement**	**2030**	**SPT**	**LR**
VSRE	**Strathaven - Smeaton OHL Conductor Replacement**	**2027**	**SPT**	**LR**
E2DC	**Eastern Green Link 1 (EGL1)**	**2030**	**NGET, SPT**	**ASTI**
TGDC	**Eastern Green Link 4 (EGL4)**	**2034**	**NGET, SPT**	**ASTI**

6.3 Streamlining and automation

6.3.1 We support the package of growth mechanism set out by Ofgem in the RIIOT3 Draft Determination. However we are concerned around Ofgem's recent RIIO-T2 re-opener decision[211], which was published without post submission engagement with us to clarify project details or costs. This decision creates uncertainty around the ability to rely on growth mechanisms, this position will be full set out in response to the decision on 26 August 2025. Including Ofgem's aim to be adaptive, "to enable the industry to meet the emerging requirements and policy developments as they become clearer over time". However, we think more should be done to ensure the mechanisms are more streamlined and automated to reduce the regulatory burden on Ofgem and accelerate transmission investment. This is in line with Ofgem's CEO's ask to network companies to "co-design a reopener process which enables Ofgem to move at pace". This is of particular importance for the Volume Driver, which has been a successful mechanism from RIIO-T2 enabling automatic funding for over 100 projects driven by new connections; yet the rates proposed in RIIO-T3 simply make the mechanism unviable.

Volume driver – automation

6.3.2 The volume driver has been an essential tool in the RIIO framework to enable the connection of new demand and generation connection for typical projects, enabling the connection of over 11GW on our network. RIIO-T3 will see connection volumes almost double to 19GW in the next 5 years, and connections reform and the gate-two-to-whole-queue (G2TWQ) exercise which will run into the first year of RIIO-T3 will provide more certainty as to which connection customers are connecting and when, than ever before. The volume driver should enable these connections to progress at pace and with minimal regulatory burden. The policy intent of the volume driver is aligned with CP2030 and accelerating at pace. **However, the calibration of the volume driver, as set out in the Draft Determination, will create a short-fall in funding of the connection projects of over £95m mainly driven by Ofgem proposing some unit rates that are lower than they were in RIIO-T2, rendering the volume driver unviable.** We've been working to expand the data set to support the re-calibration of the volume driver and have now supplied this to Ofgem, we look forward to working together to support the recalibration required, noting that risk should not wholly be managed by the stepped TIM. Our ask to Ofgem on the volume driver is:

6.3.3 Recalibrate the VD to enable and automate the investment required to connect customers at an accelerated pace. The recalibration needs to be forward looking and bottom up to include more projects, and actual costs incurred including those in our environmental initiatives (e.g. BNG and low carbon materials). We've been working to expand the data set and liaised closely with Ofgem's consultancy team and welcome further engagement to finalise by FD. As outlined, **without recalibration the VD will be unviable to use in RIIO-T3, meaning more project-by-project applications in the LR and UIOLI funds.**

[211] https://www.ofgem.gov.uk/consultation/draft-determinations-riio-2-re-opener-applications-2025-electricity-transmission-electricity-distribution-and-gas-distribution

Use it or lose it pot – automation and reduced regulatory burden on LR

6.3.4 We support the Ofgem DD proposal for the Use it or Lose it (UIOLI) pot for load projects that fall outside the volume driver, this is an adaptive regulatory mechanism with little regulatory burden. Ofgem have proposed a UIOLI pot size of £133.8m, on the basis of the total cost of 7 projects identified by Ofgem that are within scope of the Load UIOLI. Following bottom-up analysis we believe this pot could be depleted very quickly during the first 2 years of RIIO-T3 for atypical connection projects only – limiting the possibility of other projects being included in the UIOLI scope. We have proposed that the UIOLI pot size is increased to:

- £270m [a £136.2m increase]; and/or a combination of
- the pot is depleted on an annual basis following RRP reporting of costs spent

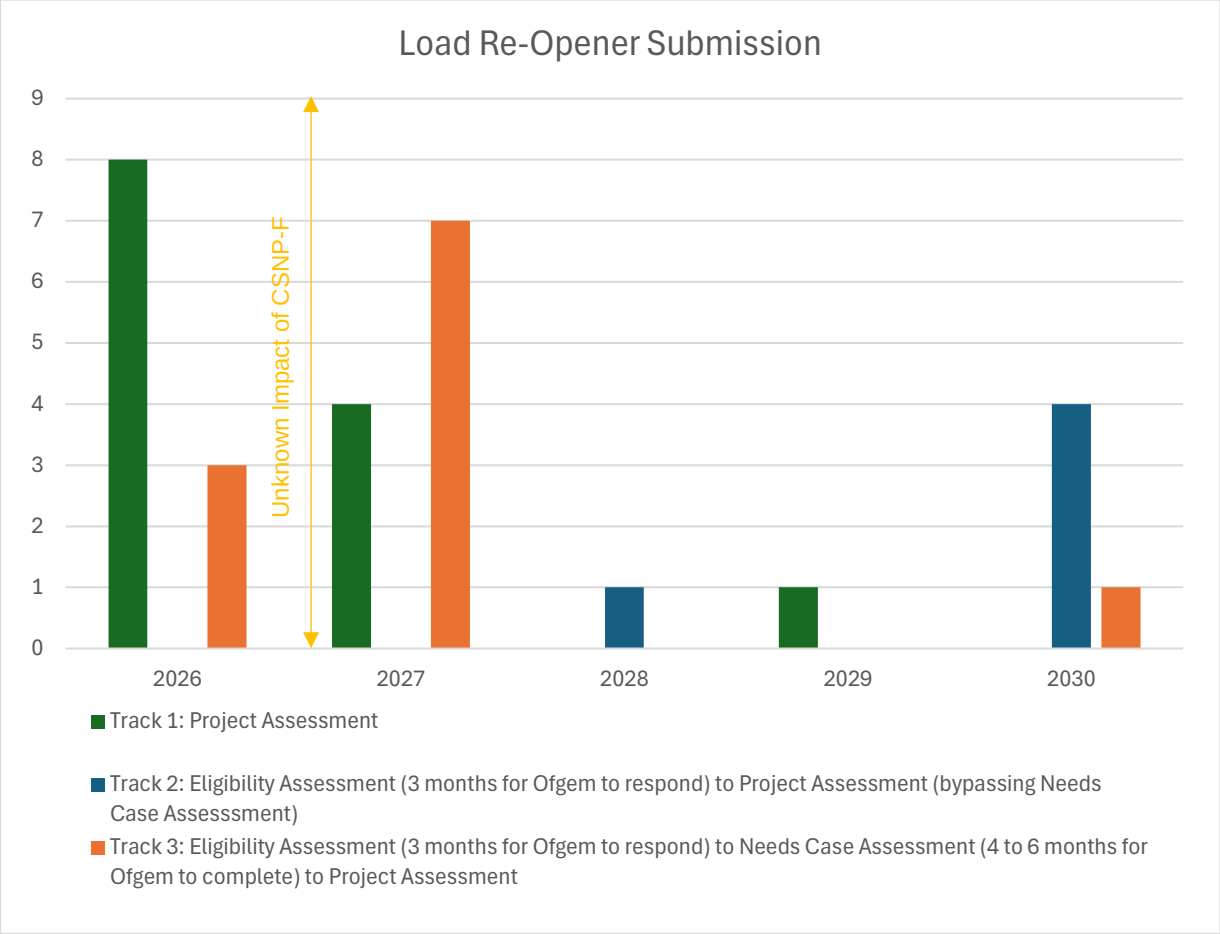
6.3.5 The UIOLI pot size and calibration are closely linked to both the calibration of the Volume Driver and Load Re-opener (LR) thresholds. If the VD is not recalibrated, this will push more projects into the 'atypical connections' project scope for the UIOLI pot. The threshold for the LR is the other determining factor, any project >£25m will be pushed into the LR. Creating unnecessary regulatory burden and increased time and costs to both Ofgem, companies and ultimately consumers.

Load re-opener – automated pre-construction funding to reduce regulatory burden, streamlined process

6.3.6 We strongly support the introduction of the LR as part of the RIIO-T3 framework, this will ensure our network is able to adapt and deliver CP2030 during the price control. In the first year of RIIO-T3 we expect to make eight cost assessment applications to Ofgem for LR scheme. In comparison to ASTI this is a significant increase[212]. Analysis does not include the impact of the first CSNP in 2027, which will likely increase the number of cost assessments further.

[212] On average, for ASTI we have submitted a cost assessment every 18 months, during the first year of RIIO-T3 we will submit 8

Figure 4-1 - Load Re-opener submission forecast to Ofgem[213]



6.3.7 To ensure the LR assessment is automated and streamlined our key asks of Ofgem are:

- Increase the PCF to 14.5% from Ofgem's DD position of 2.5%. The funding increase request considers the expanded definition of PCF to include early enabling works and as requested by Ofgem has been jointly agreed between TOs, following past and future project analysis.
- PCF to be automatic following TOs submitting eligibility application to Ofgem rather than awaiting Ofgem approval for three months. This does not follow the precedent set from ASTI to remove regulatory barriers.
- As with CSNP-F, set a COAE threshold in line with ASTI precedent of 5% rather than the 4-fold increase set by Ofgem of 20%.

CSNP-F – SREAMLINED TO DELIVER CSNP OUTCOMES

6.3.8 The CSNP-F is essential to planning the future network alongside the SSEP. It is critical to have enabling regulatory mechanisms as tools to start delivering CSNP recommendations as quickly as possible. We support the introduction of the CSNP re-opener mechanism in Ofgem DD (noting the ODI considerations listed above in Chapter 7).

6.3.9 To ensure that re-openers are as streamlined as possible we have the following key asks of Ofgem:

[213] Submission year represents either Project Assessment (Track 1 and 2) or Needs Case Assessment (Track 2)

- There must be a **clear distinction** between CSNP-F projects and LR projects[214]. In Ofgem's DDs it is unclear to which projects the CSNP-F will apply. CSNP-F should exclude connections and enabling works for smaller projects that are not wider works should fall into either the VD or UIOLI pot. Debate over which regulatory mechanisms apply to a project during RIIO-T3 will increase regulatory burden, cause delay and impact investor confidence.
- **PCF automation**: automatic PCF upon need confirmation from the NESO via CSNP, in the DD Ofgem states three months. This could provide uncertainty of funding for a quarter of a financial year and could impact project delivery as with LR. This does not follow the precedent set from ASTI to remove regulatory barriers.
- **Application windows**: Application for cost assessment must follow the publication dates of the CSNP-F rather than having fixed dates like the LR. Windows need to be flexible to allow for delays to the CSNP-F publication.

Non-Load

6.3.10 We have actively demonstrated the gap in the price control framework for asset interventions where the need case is not evident at the time of business plan submission, particularly in relation to non-NARM assets. There is a need for a non-load re-opener to fund necessary works to manage asset condition and risk issues. TOs cannot as suggested in DD "manage within their existing baseline allowances" for interventions on emerging asset issues. This would entail the non-delivery works that Ofgem has already determined to be in consumers' interests in order to fund works to resolve an emergent issue. We request that Ofgem reconsider the eligibility criteria to include works to address network and asset risk which are not related to cancelled load projects.

[214] The definition between CSNP-F and LR track 1 projects is blurred. There were two distinct difference of LR and CSNP-F: 1) use of ITA 2) project ODIs. This is now blurred – our ask to Ofgem in order to streamline for clear definitions for each track, including criteria for ITA and ODI (including small CSNP projects)

GROWTH MECHANISMS QUESTIONS

ETQ 22 Do you agree with our proposal to introduce the CSNP Co-ordination LO?
We strongly oppose the introduction of a CSNP co-ordination licence obligation (LO). The System Operator Transmission Owner Code (STC[215]) and System Operator Transmission Owner Code Procedures (STCPs) define the relationship between the transmission system owners and the system operator. We recognise that effective cooperation is crucial for developing robust system models, setting project delivery dates, cost estimates and engineering designs that meet minimum requirements and that a TO has vital data to support economic assessments and that if it is not provided effectively it may compromise the quality of the NESO's outputs. In light of the proposed new licence, we were disappointed that NESO were unable to attend the first post-DD engagement [216] with Ofgem, despite having prior notice. We do understand that unforeseen circumstances can arise; however, as a TO, we make every effort to ensure representation and active participation in such meetings to help avoid delays in development.

We acknowledge the Ofgem rationale that a new licence co-ordination obligation will allow enforcement, we would reiterate, as stated in the cross TO meeting with Ofgem[217], that the STC itself must be complied with under the current standard licence conditions, meaning that cooperation is currently incorporated as an obligation and TOs may face enforcement action as things presently stand. The STC can be amended quickly as required and if necessary to alter TO/NESO interactions, which is more efficient and a faster process than a LO and associated guidance document.

Replicating the STC in the licence, under a new licence obligation will go no further than our current co-ordination actions, TOs comply and work with the existing STC and STCP documents[218] which consider co-operation, long term planning, immediate system operation co-ordination, dispute resolution and data exchange working amongst other wider reaching interactions. As a TO we have already supported the Network Options Assessment and Holistic Network Design processes and worked within the STC / STCPs to provide information as required. We would highlight the ongoing work with the NESO to increase and improve data sharing information procedures.

We have a number of concerns regarding key areas of the CSNP Co-ordination LO proposal:

Data sharing – Many processes between the NESO and TOs have previously been informal, including data sharing, as we indicated above and acknowledged by Ofgem there is ongoing work to try and address data sharing. Given the change in the status of the NESO, which is now a public body, some aspects of the data sharing practices have to be addressed as historical behaviours are no longer appropriate, given for example the Freedom of Information regime or Environmental Information Regulations and the extended obligations of a public body to comply. There needs to be a focus on NESO requesting specific requirements for TOs data, rather than broad sweeping collections of data and NESO should reference previously received information rather than re-requesting data already received.

NESO role - The role of the NESO in reporting TO behaviour is a crucial part of the co-ordination LO proposal. This takes NESO beyond the role of System Operator, allowing them to make potentially qualitative assessments on TO behaviour, with little insight to Ofgem of mitigating behaviour or situational information. Further concern that the NESO will not face similar scrutiny of their requests to TOs and consideration of information requests being of sufficient quality to respond appropriately seems lacking within the DD proposal.

We have responded to the recent NESO consultation the CSNP Methodology[219], currently the methodology omits key detail and specificity is currently missing, which needs to be included for us as a TO to be able to understand and deliver our requisite contributions to the CSNP. Within a recent CSNP

[215] Section H; specifically outlines the route to solve disputes - A Party may raise a Dispute by issuing a Dispute Notice to the Authority and each of the other Dispute Parties.
[216] Cross TO / Ofgem meeting: Tuesday 12 August '25.
[217] Cross TO / Ofgem meeting: Monday 26 May '25
[218] Detailed mapping of the STC & STC-P interactions: Microsoft Word - Feb 2008 Mtg 1 Paper STCP to STC Section Mapping.doc
[219] https://www.neso.energy/document/363521/download

steering group[220] NESO acknowledged that there is still much work to be done in the CSNP space, given this is the current position we suggest a specific LO is not appropriate.

Clear and efficient processes – SPEN emphasise the importance of clear, efficient processes and express concerns about a potential new LO overlapping with existing obligations and the adequacy of current Ofgem resources to manage new requirements. In addition, we would also highlight that NESO TO co-ordination behaviour is also proposed to be incentivised through the new Innovative Incentive ODI (NESO collaboration).

When considering a NESO co-operation obligation, CSNP is just one aspect of the responsibilities TOs work on with NESO. There are already several cooperation licence obligations[221] for TOs and SPEN question if a holistic licence condition on supplying information, giving clearly defined standards for compliance (why, what, how, when, associated methodology, development requirements, process) which could be replicated in the NESO licence would be more appropriate to consider? Although this would need careful and considered drafting, to consider its interaction with the STC, which is intended to govern and set out all data exchange requirements between the NESO and TO's. This is especially relevant given the reliance and indication of a guidance document for the CSNP LO which is presently unwritten, meaning the obligation is unclear in its requirement of TOs for us to assess.

ETQ 26 Do you agree with our intended approach to PCF in RIIO-ET3?

We welcome Ofgem providing further clarity on their definition of PCF and EEW activities which helps to support the appropriate regulatory treatment for critical early project development works.

As per Ofgem's request we have led the cross TO development of the updated PCF to develop a coordinated and consistent view on what the right level of funding that is required to ensure the effective and efficient development of projects throughout the RIIO-T3 period, this work is ongoing and we expect to report back to Ofgem within their agreed timescales. To continue our commitment of being transparent as possible throughout the RIIO-T3 planning process we have outlines our position on Ofgem's intended approach.

Whilst we recognise that the introduction of the APM will go towards supporting early procurement activities which was originally included within ASTI Early Construction Funding. There still remains a substantial funding gap to cover critical activities such as Early Enabling Works and purchase of land. This response is split into three parts:

1. We outline, an updated position on PCF for a like for like comparison to the previous definition
2. PCF has then been updated to include EEW following Ofgem's updated definition in DD
3. We have also included our analysis to address the uncertainty around strategic land purchasing

1. PCF % - like for like	2. EEW %	3. Land Purchas %	Total
3.31%	11.20%	1.82%	16.33% (14.51% excluding Strategic land)

1. PCF – *like for like comparison*
We are deeply concerned with Ofgem's current proposed approach to PCF which we believe will create unnecessary regulatory burden and potentially delay the critical early development of projects. We urge Ofgem to ensure that PCF is **automatic** upon submission of eligibility letter as a quarter of a year could cost a significant amount of time and delay delivery.

Based on the current definitions of PCF 2.5% is no longer a suitable value to support project development and the activities laid out by Ofgem. The cross TO position is to reflect the current economic climate and take learnings from our ASTI portfolio submissions. Our bottom-up analysis across relevant projects[222] that PCF should marginally increase to **3.3%** of the total project costs and should be set on a programmatic basis which will provide a consistent approach and align with Ofgem's introduction of the APM. This will provide the TOs the sufficient regulatory funding to undertake essential activities required

[220] CSNP Steering Group 5th August. First working group post CSNP methodology consultation.
[221] E.g.: Licence Special Condition's: 9.10 Network Access Policy, 9.11 Provision of information to the ISOP,
[222] 10 strategic projects and 19 core projects across our RIIO-T3, tCSNP2 and ASTI portfolios

to develop projects effectively and efficiently. It is also important to note that we advocate for Ofgem to continue to undertake their robust assessment of these costs to ensure that they are economic and efficient when undertaking their project assessment.

It is also important to note that, subject to the work undertaken across the TOs to present an agreed percentage it is likely that there will be instances where project PCF could be less or more than the proposed 3.3%. In the instances where more funds are required, we urge Ofgem to remain flexible to ensure that TOs have a reopener route to increase their PCF by providing evidence when required.

2. EEW – *updated definition of PCF*
Currently there is no route for TOs to fund Early Enabling Works in an efficient and prompt manner, waiting till the project assessment stage to have these funds approved is not practical in the current accelerated highly competitive environment that we operate in. It is therefore imperative that Ofgem provides TOs early access to these funds to avoid any potential delay in project development. We have analysed a large sample of projects[223] to determine what value would suitably fund Ofgem's defined activities. The list of activities although could be improved is an extensive list of essential activities that are imperative to early project development. From our assessment early enabling works would require **11.2%** of the total costs. We would advocate that this is included within PCF as per Ofgem's DD and follows the same regulatory treatment, with the appropriate consumer protections as PCF.

If Ofgem were to exclude strategic land, this would result in 14.51% PCF funding to include EEW for RIIO-T3.

3. Strategic Land – *uncertainty around early access funding*
We strongly oppose Ofgem's decision to exclude strategic land purchases from the scope of early development funding. While it is true that TOs have historically accessed funding for land through cost assessments under mechanisms such as SWW, LOTI, and MSIP, this legacy approach is no longer adequate given the scale, urgency, and complexity of the infrastructure required to meet net zero targets. During a recent meeting with Ofgem's major project team and engineering team, this was understood and agreed for the tCSNP2 project 'CMN3' aka 'Cross Border Project'[224].

Given that the energy landscape continues to rapidly evolve since the introduction of ASTI Excluding early access to fund strategic land activities is outdated and misaligned with the realities of accelerated delivery throughout the RIIO-T3 period. Purchasing land strategically is a critical enabler of timely and cost-effective transmission development. Excluding it from PCF risks undermining the very objectives RIIO-3 is designed to achieve. Our position is set out in detail below, supported by real-world case studies that clearly demonstrate the critical importance of securing funding for strategic land acquisition.

Strategic Land Funding is Critical to Timely Delivery
The scale and urgency of the transmission build-out required to meet net zero targets necessitate early and proactive land acquisition. Delays in securing land could lead to significant project slippage, increased costs, and missed decarbonisation milestones. The use of early funding for strategic land purchases is not speculative it is an essential enabler of timely delivery. The current cost assessment routes are retrospective and administratively burdensome, requiring full project assessment before land costs are approved. This undermines the ability of TOs to act quickly in competitive land markets, where opportunities can be lost. Early land acquisition can de-risk projects, reduce future costs, and avoid the need for costly compulsory purchase processes. These benefits ultimately flow to consumers. Excluding early access to funding for strategic land risks higher long-term costs and inefficient delivery.

Early access to funding for strategic land supports effective working in an outdated planning regime
The planning regimes in Scotland remain a significant risk to accelerated delivery of transmission infrastructure, notwithstanding the introduction of the Planning and Infrastructure Bill. We have seen critical projects 'stuck' in the current planning regime for up to 5 years. The ability for TOs to negotiate the procurement of land quickly and efficiently can mitigate programme risks as a result of planning delays. If the route to fund land purchases is not available at the earliest possible stage, this opens up a further risk for TOs to navigate in turn adding to timescales of procurement. This may also lead to the TOs having no

[223] 10 strategic projects and 19 core projects across our RIIO-T3, tCSNP2 and ASTI portfolios
[224] Meeting 21.8.2025 – CMN3 project update

option but to progress through the CPO route which could add multiple years to the development of critical projects.

The amount of land negotiations and potential purchase for RIIO-T3 is unprecedented. As per our previous communication with Ofgem it is imperative to note we own very little surplus land beyond our operational portfolio and do not sell land for profit.

The combination of high demand, limited supply, and strong investment potential makes the Scottish land market highly competitive.

The UK's commitment to transitioning to a low-carbon energy system has spurred significant growth in the renewable energy sector, particularly in wind, battery storage and solar generation. The need for land to support essential grid infrastructure, such as electricity substations, has surged significantly, becoming a central focus within the energy and real estate sectors. As demand continues to grow, challenges related to land availability and utilisation are expected to increase. We and other TOs are in direct competition with other energy developers for the same land. The later in the project development process TOs are able to progress land purchases, the more likely it is that developers will purchase desirable land in close proximity to TOs planned works, increasing the total cost to consumers.

Within our area throughout RIIO-T3 there is approximately 13.6GW of onshore wind expected to connect and according to the NESO's estimations this would require 122,400 acres of land across central and southern Scotland. As outlined in response to ETQ11 we also face increased pressure from the growing need for land due to increased biodiversity.

Currently we have applications associated with data centres totalling c.6.8GW. According to Soben construction consultancy[170] 'hyperscale' data centres can exceed 40 acres requiring significant amount of suitable land for construction. In June 2023, the Scottish Futures Trust published that 12 'first class' data centre sites had been identified across Scotland[171]. Data centres alongside renewable generation continue to increase the pressure on land availability suitable for energy use in Scotland. This ongoing and ever-increasing demand intensifies the global competition for land across Scotland.
The race to procure land has been further heightened with the recent decision by Ofgem and the NESO on connections reform where the new 'gated' approach to connections require developers to provide proof of landownership or a land option agreement in order to obtain a queue position.

TOs Should Not Bear Disproportionate Risk
While Ofgem suggests that TOs are best placed to manage land risk, this ignores the fact that strategic land is often acquired in the public interest to enable nationally significant infrastructure. Ofgem's expectation of TOs to shoulder this risk without upfront funding could create a disincentive to act early and responsibly.

The value of substation land depends on many factors like location, site size and configuration, proximity to both energy sources and existing infrastructure, ground conditions etc. When all things are equal and sites are suitable, we evidence below that the value driven by "energy use" land values.
Renewable generation and battery storage are turning out to be a distinct driver of value. More broadly clusters of land suitable for energy infrastructure are resulting in significant pockets of distorted land values with "Energy Use" premiums being applied.

Ofgem are correct to state that land purchased for transmission infrastructure could be resold at a later date however this does not mitigate risks. It is unlikely that the TO would recover their full investment as any onward sale would be based on current land use values without the addition of an energy sector premium as no renewable developers would seek to purchase the land without the supporting infrastructure.

We have experienced a consistent rise in substation land values across multiple recent transactions, driven largely by increased competition from energy developers seeking land for alternative energy uses. This trend is supported by an independent report from Blackhall & Powis, which found that freehold land for "Energy Use" in Scotland typically commands between £65,000 and £150,000 per acre, with leasehold values ranging from £35,000 to £125,000 per acre per annum. In stark contrast, Farmers Weekly reported the average price of arable land in Scotland in 2024 at just £7,000 per acre.

While Ofgem suggests that TOs could mitigate the risk of stranded land by reselling it, the evidence indicates that land repurposed for non-energy uses could lose 80–94% of its value. This represents a significant and underappreciated project risk.

A Balanced Approach is Required
We propose that Ofgem consider the inclusion of strategic land within PCF to streamline the regulatory process. Alternatively we would also support early funding being made available for strategic land through a UIOLI reopener, with clear criteria for eligibility, transparency, and clawback provisions if land is not ultimately used by way of current consumer protections. This would strike a balance between accountability and agility.

To address the urgent need for early access to funding to support strategic land purchases. From our analysis, we estimate cost to purchase land to deliver our strategic projects throughout RIIO-T3 would require 1.82**%** of total project value subject to detailed design, engineering studies and landowner negotiations.

If Ofgem were to include strategic land, this would result in 16.33% PCF funding to include EEW and strategic land for RIIO-T3.

ETQ 27 Do you agree with our updated definition of EEW?
We broadly welcome the revised and updated definition of Early Enabling Works (EEW), particularly the inclusion of illustrative example activities, which provides greater clarity.

We strongly believe it is essential that the definition remains sufficiently flexible to accommodate project-specific requirements. Each project will inevitably involve a unique set of early enabling works, with associated costs that can vary significantly, for example, the construction of access roads or public road improvements may differ substantially between projects.

We welcome Ofgem's recognition that the use of EEW is not limited to a prescribed list included in the Draft Determination. However, we note that several key activities should be included to ensure comprehensive coverage.
We recommend that the following activities be considered for inclusion within the definition:

- Preparation of discharge planning conditions
- Seasonally constrained activities, such as tree or vegetation removal, works around watercourses, protected species, or flood alleviation schemes. While some of these may fall under the existing "Forestry" category, listing them would improve clarity.
- Site enabling works
- Associated project management and indirect costs

ETQ 28 Do you agree with our proposed approach to PCF on tCSNP2 projects?
We have set out our view on the proposed PCF for RIIO-T3 in response to ETQ 26 above which emphasises the concerns that are also applicable to our tCSNP2 portfolio of projects.
As for our view on the process for accessing PCF allowances for the tCSNP2 projects, we welcome the approach being proposed by Ofgem. It is critical that our projects continue to be delivered at pace and Ofgem's position to provide comfort both in the guidance document for the tCSNP2 projects and the confirmation in the RIIO-T3 DD that PCF allowances will be available for economically and efficiently incurred spend provided the activities are critical to the project's delivery programme.

However, we stress the importance of ensuring that any further delay to the tCSNP2 refresh process does not act as a blocker for tCSNP2 projects to progress. We have shared with Ofgem that we anticipate undertaking PCF activities from January 2026 onwards. These works will be essential as any delay in progressing these activities could have a detrimental impact on the delivery date of our tCSNP2 projects. Nevertheless, we welcome Ofgem's understanding and clear commitment to not be a blocker for the progression of the tCSNP2 projects and we welcome continued engagement with Ofgem on this. We iterate the need for any PCF (inc EEW) FD decision, which arises from DD reports and additional Ofgem engagement, to be reflected in the tCSNP projects.

ETQ 29 Do you agree with our proposed scope, re-opener windows and materiality threshold for the Load Re-opener?

While SPEN broadly agree with the proposed scope, re-opener windows, and materiality threshold for the Load Re-opener (LR), SPEN believe there are important considerations that remain unaddressed and aspects of the design and operation that require further refinement, as outlined in our response to ETQ 30.

Materiality threshold

As noted in the chapter response 6, the calibration of the volume driver is critical to the load package of RIIO-T3. We cannot support a lower materiality threshold until we have certainty that the volume driver will not create underfunding, which is currently the case with c.£95m underfunding.

MSIP impact

In particular, SPEN are concerned that the current framework does not account for projects that received MSIP Stage 1 approval from Ofgem during the RIIO-T2 period. These projects have already had their need case and optioneering approved, and as such, SPEN maintain—as per our previous feedback[225]—that they should be included under Track 1 and provided with PCF in the FD. However, due to the absence of an EJP submission for these projects (given that the projects had been approved and therefore it was not required to resubmit and EJP at the time), they may not be captured under the definition of "approved in our RIIO-ET3 FD" as stated in paragraph 4.58 of the RIIO-3 DD – Electricity Transmission Annex.

PCF automation

SPEN are also concerned around the paragraph 4.65 of the RIIO-3 DD – Electricity Transmission Annex stating, "We will aim to provide a response to the Eligibility Letter within 3 months of the TO's submission". SPEN believes that PCF should be **automatic** upon submission of eligibility letter as a quarter of a year could cost a significant amount of time and delay delivery. This could have a significant impact on projects, during this stage uncertainty of funding can delay critical project stages such as starting environmental impact surveys, most of which are seasonal dependent, missing a three month period could cost the project a year in reality. This follows the current ASTI framework where submission of deliver plans allow access to PCF funding, as has been the case with our Western Link 2 Projects (a provisional ASTI which required a delivery plan submission to Ofgem in March 2025).

Eligibility letter criteria

Additionally, it is difficult to provide a definitive view on the proposed Eligibility Letter at this stage, we request Ofgem share the draft Load Re-opener Guidance as soon as possible to give TOs early sight and the opportunity to collaborate with Ofgem to ensure certainty on the proposed letter content. Greater clarity is needed on what is meant by "high-level indicative requirements," especially since the LR-Eligibility template discussed during the working group sessions appeared to be far more detailed than what would typically be considered "high-level." We proposed during the working groups that the EJP criteria from RIIO-T3 would align with the requirements and provide consistency with baseline projects.

Cross over projects

The LR needs to include a trigger for funding adjustment to cover 'crossover' projects that require costs to be incurred in RIIO-ET3 to facilitate delivery in the first or second year of RIIO-ET4. This is important as it will ensure there are no funding gaps. It is also consistent with the approach proposed for the Volume Driver in paragraph 4.108 of the RIIO-3 DD – Electricity Transmission Annex.

LR volumes

It is vital that Ofgem ensure that all UM are calibrated appropriately to reduce regulatory burden as all TOs are planning to submit significant volumes of applications in the first re-opener window. Please see chapter 6 summary which outlines our projects portfolio submission to Ofgem.

COAE- please see ETQ38 for our response to COAE for both LR and CSNP-F.

ETQ 30 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 in principle but there are significant issues with regard to their design and operation. While we agree that a means of reducing regulatory burden is a desirable objective, we repeat our previous feedback[226] to Ofgem that the design of PASE is flawed, could offer perverse incentives,

225 Ofgem SPT site visit presentation 24.4.25, Load WG 22.4.25, issue log sent 5.5.25
226 SPT-Ofgem Bilateral Meetings on 20/08/2024, 18/03/2025 and 18/08/25

and has the potential to generate poor consumer outcomes. We provide detailed commentary in the following paragraphs.

- **Linear, new routes**: It is unclear why only double circuit routes are considered for fast-tracking when single-circuit designs using wood poles at 132kV for individual connections is very often the correct solution. This will unnecessarily push relatively simple connection projects which are outside the volume driver threshold into Track 3. Amending the definition could avoid this. The concept of maximum ratings, if not carefully defined could result in unnecessary works and costs to consumers. The design of overhead line supports and conductor systems is a multi-variable task and simply put, the definition will encourage the largest structures with the highest rated conventional or HTLS conductors which would result in circuit ratings that may not be appropriate for the application because that excess capacity could not be exploited. More careful drafting is required to ensure that due consideration is given to the usable rating (considering future requirements) and other parameters such as routing and consenting.

- **Linear, reconductoring**: Unnecessarily highly rated conductors may have excessive costs for tower and foundation strengthening. Alternatively, higher cost HTLS conductors could be specified without adequate need and they would simply be fast-tracked.

- **Dynamic Line Rating**: these are effective solutions with the potential to provide additional thermal capacity in operational timeframes. However, the costs should not, in all cases, be borne by consumers. In the case of connections subject to customer choice access restrictions, DLR solutions could limit their curtailment volumes without wider system benefit but it's not clear that this benefit should be funded by consumers. Conversely, on circuits where increased thermal ratings could result in reduced constraint costs, there is a clear case for price control funding. The distinction must be made and demonstrated by licensees; blanket acceptance of DLR is not appropriate and the definition should be amended.

- **Non-Linear, new substations**, Air Insulated Switchgear: the special status awarded to AIS substations may conflict with licensees' obligations under Section 9 and/or Schedule 9 of the Electricity Act because the fast-tracked solutions may not be the most economical, efficient or co-ordinated nor those that are consistent with the licensee having given due regard to amenity. It is also in direct contradiction with paragraph 4.79 of the ET Annex and paragraph 5.7 of the SPT Annex. This contradiction means that, in effect, the concept of PASE for new-build substations is null. In order to demonstrate that the proposals are economical and efficient, and have due regard to the preservation of amenity, it is necessary for licensees to assess the range of feasible solutions for their alignment with these obligations. Simply stating in this document that one type of solution will not require to comply with the aforementioned paragraphs does not relieve the licensee of their obligations under the Act and leads to regulatory uncertainty. Notwithstanding this point, we offer the following additional comments.

    - By stating a presumption for AIS, and therefore a presumption against GIS (proposals for which would require additional justification **over and above that to comply with the licensee's statutory duties and the criteria stated in 4.79 of the DD ET Annex** that Ofgem consider unnecessary for AIS solutions), Ofgem are risking introducing delays and complications to projects that are critical to achieving government targets. Consenting processes have previously heavily scrutinised the economic justification for projects (e.g. Kendoon to Tongland Public Inquiry Report, paragraph 2.5). Where a GIS solution is determined to be the option that fulfils a licensee's obligations under the Electricity Act, it is possible that consenting authorities and objectors may seek to scrutinise this negatively in light of Ofgem's stated presumption in favour of a different solution from that proposed by the licensee.

- **Non-Linear, substation extensions**: there appears to be no reason to give special status to the extension of AIS substations nor to limit the special status to double busbar configurations. If

extension of an existing substation is deemed to be suitable for track 2 then its switchgear technology or configuration are irrelevant. Ofgem are missing an opportunity to accelerate their decision-making, noting that extensions are likely to be greater in number than new substations.

ETQ 31 Do you agree with the scope and materiality threshold for the Load UIOLI?
We are strongly supportive of the Load UIOLI pot for RIIO-T3, this streamlines the regulatory process making project progression more automatic, supporting the acceleration of transmission. However, we believe this could be streamlined further by extending the scope and materiality threshold proposed for the Load UIOLI mechanism. However, we believe the Load UIOLI needs to include a trigger for funding adjustment to cover 'crossover' projects that require costs to be incurred in RIIO-ET3 to facilitate delivery in the first or second year of RIIO-ET4. This is important as it will ensure there are no funding gaps. It is also consistent with the approach proposed for the Volume Driver in paragraph 4.108 of the RIIO-3 DD – Electricity Transmission Annex. Additionally, SPEN would like to raise several further important considerations:

1. **Funding Level for SPT (£133.8m[227]):**
   We believe the funding level warrants further scrutiny, the number of projects (and level of funding) of this pot is wholly dependent on the VD calibration. In light of the new RIIO-T3 Volume Driver. The revised driver is expected to perform worse than the RIIO-T2 Volume Driver due to generally less cost-reflective rates and the removal of the fixed term. This could significantly impact the efficiency and adequacy of funding under the current proposal. The impact of this would be a requirement to increase the number of projects which are eligible for inclusion in this mechanism, requiring an increased funding level.

2. **Reopener Mechanism for UIOLI Pot Size:**
   We would also like to reiterate our previous feedback[228] to Ofgem regarding the inclusion of a reopener mechanism. Specifically, we recommend that this be applied to the overall pot size rather than on a per-project basis. Given the potential number of projects, a pot-level reopener would provide greater flexibility and responsiveness if the predefined UIOLI pot is fully utilised during the period.

3. **Scope of the UIOLI**:

The mechanism should be designed to ensure projects started within RIIO-T3 are funded under the pot. two considerations are required:

- the UIOLI pot size should therefore be sufficient in size to cover projects in this crossover period, to avoid the challenges currently being faced to bring crossover RIIO-T2/T3 MSIP projects under the LR.
- the mechanism should cover a period of RIIO-ET3 + 2 years.

There is an amendment to the scope that is necessary to ensure TOs can comply with their statutory obligations:

- Recognising TOs' networks are interconnected, where Ofgem have approved one licensee's project that trigger minor works in another TO's network (for example, protection changes, overhead line tower identification etc.), the UIOLI mechanism should be extended to provide automatic funding to the 'affected' TO.
- We also not the current licence drafting for Ofgem to make a decision by direction impact the companies CMA appeal rights.

4. **Consumption of the UIOLI pot size to reduce regulatory burden**

   Within the UIOLI pot there is a presumption that the metric for 'consumption' of the pot is the project "total cost", costs which can be spent across several years of the price control. We

[227] This has been corrected from Ofgem following a DDQ – DD position is £122.1m
228 Cross TO Ofgem led Load WGs 03.02.25 and 22.04.25

believe this is unduly restrictive. Rather a different methodology for pot depletion should be considered, it would be more appropriate to measure consumption based on **project commitments** ie actual costs and contracts placed. This would work with an annual review of project costs within the normal RRP process. In parallel, where a project has completed, the project costs for it are 'removed' from the pot, allowing the pot to be "replenished" in size. This would work, as there is no need for costs to be within the UIOLI pot once work is complete as the project will be assessed as part of the RIIO-T3 close-out process and tested for efficiency. This methodology would allow the UIOLI pot to function more flexibly enabling delivery at pace whilst still retaining regulatory oversight. We suggest that this proposal would reduce the use of a re-opener to reset the pot size and therefore reduce regulatory burden for Ofgem and TOs.

ETQ 32 Do you agree with our proposed design of the generation and demand connections volume driver mechanisms?
The substantial increase in generation and demand connections since RIIO-T2 underscores the importance of a fair and well-calibrated volume driver to support efficient project delivery and mitigate delays.

We support the need to review and revise RIIO-T2 rates and have been working to expand the data set to support recalibration of the proposed Ofgem DD VD rates, we note several concerns with the current proposal which are listed in detail in response to SPTQ 6. However, as proposed there is a significant funding gap that cannot be closed as this mechanism is currently calibrated. The more than four-fold increase in the materiality threshold to enable a connection project to be eligible for either the Load UIOLI or LR means that the volume driver mechanism is effectively non-functional and there is no proper funding of efficient costs. The following are summaries of the key issues with the current definition of the mechanism.

- The proposed **driving variables** are broadly appropriate; however, further **disaggregation by voltage** would enhance transparency and accuracy.

- Some **regression models rely on limited observation counts**. We propose that Ofgem should consider expanding the RIIO-T3 BPDT dataset to incorporate **all contracted projects**, consistent with the RIIO-T2 framework.

- The **RIIO-T3 Best View BPDT submission** – for Generation & Demand connections - was based on a probabilistic assessment of customer-driven projects going to completion to ensure the highest level of accuracy in our forecasting. Our submission included c50% (high/ medium probability) of total contracted obligations. There is, therefore, further data available that can be used to facilitate a fuller view of the range of solutions and costs that can assist in the calibration of the volume driver unit costs.

- The **omission of a fixed allowance** element leads to under-funding of projects. Ofgem should reconsider their decision to remove the fixed allowance from the RIIO-T3 VDUM.

- It is necessary for Ofgem to embed the costs of **environmental policy** decisions in the rates for the volume driver. The volume driver will be the only means of recovery of costs associated with Biodiversity Net Gain and low carbon construction materials (e.g. concrete and steel) for projects which it is intended to fund.

- **Adjustments to RIIO-T2 unit costs should** reflect both **inflation and Real Price Effects (RPEs)**. RPEs need to take appropriate account of the continued challenges with supply chain capacity and its impact on costs. It is not clear, from analysis conducted by Oxera that the RPE methodology has substantively changed from that set out in RIIO-T3 and so may not be reflective of overall cost changes in RIIO-T3 (see also our response to OVQ18). It also appears from our analysis, that the RIIO-T2 rates for Overhead Line (new and reconductoring) has simply been inflated from 2017/18 prices to 2023/24 prices. Meanwhile, the RIIO-T2 rates for underground cable (>1km) have decreased by 37%. This is inconsistent with our evidence from recent contracts and observed price increases. On average, underground cable installations exceeding

1 km cost approximately £2.287 million. In contrast, Ofgem's RIIO-T3 VDUM rates allocate only £0.34 million per kilometre—resulting in a shortfall of around 85%.

ETQ 33 Do you agree with our proposal to apply the 'stepped TIM' to volume drivers as part of general totex?

It is vital to ensure accurate calibration and reasonable unit rates for the different cost categories within the Volume Driver. The volume driver is an essential tool to enable projects with little regulatory burden on both SPT and Ofgem – it's been effective in RIIO-T2 enabling over 100 connections projects reported in the RRP. We agree that the Stepped TIM should apply to the Volume Driver. The stepped TIM should apply to out-turn costs, including generation and demand connection costs covered by the volume driver. This approach provides valuable protection against various potential cost pressures. The stepped TIM, however, should not act as a backstop to a poorly calibrated Volume Driver. The volume driver should be recalibrated to provide an automatic, efficient and economic mechanism without over reliance on the TIM to encourage efficiency from TOs. Otherwise the VD will be ineffective for RIIO-T3 pushing more projects into the LR, requiring more Ofgem submissions, resource and ultimately costs to consumers.

ETQ 34 Do you agree with our proposed methodology for excluding atypical connection projects from the regression model?
We understand the rationale for the proposed approach. We agree that any atypical projects should be excluded from the modelling for unit rates. It is important to recognise that atypical projects will occur due to connection technology differences, generation capacity, location of connections and proximity to the Main Interconnected Transmission System (MITS). We do not agree with using the interquartile range to exclude outliers. Instead, we recommend applying Cook's Distance, which is more appropriate for regression analysis as it assesses the influence of each data point on the overall model by accounting for both leverage and residuals. In contrast, the interquartile range identifies statistical outliers based solely on data spread, without considering their effect on model performance.

We endorse use of the LR mechanism to capture atypical projects not covered by VD or UIOLI. It remains important for the majority of our portfolio to be accommodated within the VD or UIOLI frameworks to support streamlined delivery.

ETQ 35 Do you agree with our proposal to use the Load Re-opener (above £25m) and Load UIOLI (below £25m) to fund projects that fall outside ±1.5 standard deviations from the regression model?
The monetary value of 1.5 standard deviations is a clear indication that the modelling of cost rates is failing to provide cost-reflective funding.

We welcome the introduction of a separate mechanism (UIOLI) to fund projects failing the performance test where the total direct cost of the project is under £25m. This is a positive approach to enabling quicker decisions, whilst retaining accountability. We do, however have concerns over the threshold for volume driver projects. Ofgem have proposed a threshold of 1.5 times the standard deviation. For us this results in a threshold of **±19.86m - 468%** increase from the RIIO-T2 threshold. Although this increases the number of projects funded via the volume driver mechanism, it also exposes us to a greater level of risk. Based on Ofgem's proposed DD rates, 84% of our contracted portfolio of RIIO-T3 Schemes will be funded under volume driver. However, these projects will be underfunded by a total of £94.52m. **As a result, the UIOLI mechanism will support less than 6% of our contracted portfolio**. The very high value of the threshold (and hence the standard deviation) is further evidence of the flawed model of volume driver rates used by Ofgem and that it is failing to provide cost-reflective allowances.

The clear under-funding of connections projects by flawed cost rates and an unusable trigger for the LR or UIOLI is detrimental to expediting delivery for customers given the number of connection projects that we are currently contracted to deliver over the seven years of RIIO-T3(+2). As it stands, we are currently contracted to deliver over 350 generation and demand projects during the RIIO-T3 (+2) period.

It is also not clear how the mechanism is anticipated to work over the period; for example, is it automatically replenished e.g. if a project in the 'pot' is delivered can it be withdrawn and replaced by another project. See ETQ31 for our proposal.

Likewise, we support the decision to fund atypical projects exceeding £25m via the LR, recognising their scale and complexity. Given the administrative burden of this route, we believe it is essential that LR be reserved exclusively for genuinely atypical schemes and ensure that an ill-designed volume driver mechanism does not cause excessive numbers of projects to require LR submissions (noting that the materiality threshold must also be revised to a practical value to enable the use of LR for these projects). We need to ensure, recognising that these are customer-driven works crucial to net zero deliverables, that the re-opener mechanism is streamlined and flexible enough to facilitate quick decisions. It needs to be able to process funding requests (given the certainty of need) in a timely manner over the full period of the RIIO-T3 Volume Driver tenure i.e. seven years.

ETQ 36 Do you agree with our treatment of RIIO-ET3 Volume Driver crossover projects and our approach to allowance profiling?
The development and delivery of projects has become a more protracted and complex process due to several factors e.g. supply chain volatility, global geopolitical factors, planning approvals, consents, bio-diversity loss etc. A longer time horizon associated with connections funding provides greater certainty in relation to contractual commitments. We support Ofgem's proposed treatment of RIIO-T3 crossover projects and its approach to allowance profiling, recognising the need for flexibility in response to evolving construction timelines and market pressures.

Experience in delivering projects and illustrated by RIIO-T2 evidence longer development periods e.g. 3-4 years (with lower costs) & construction phase (2-3yrs). This can create a distortion between costs and allowances with fixed price control periods (5-years). This is problematic – at the boundary - where projects deliver in next price control and can be exacerbated by a fixed annual allowance profile of 25%. As a result of the significant growth in the number of connections contracted in RIIO-T2 the profile of allowances is becoming more significant. An alternative approach may be adoption of a (single) simplified S-curve profile for allowances that more closely mimics the cost profile of a project.

ETQ 37 Do you agree with the proposed scope of the CSNP-F Re-opener?
See Chapter 5 in relation to the ODI-F aspect and scope of CSNP-F.

SPEN support the scope of the proposed CSNP-F re-opener recognising that it will include projects that arise from the CSNP publication and other NESO led network plans. We would urge Ofgem to include all NESO projects which have confirmed needs case to be in the CSNP-F re-opener, allowing TOs automatic access to PCF as per paragraph 4.41 of the DD consultation.

Enabling works and connections works will be incentivised under the connections capacity ODI and funded through either the VD, UIOLI pot or LR therefore these projects should not be included in the CSNP-F definition.

Please see our response to ETQ 26 for further comment on PCF.

ETQ 38 Do you have any views on our proposed design of the CSNP-F Re-opener?
We have concerns about the methodological approach of the of the CSNP Re-opener as defined in paragraph 4.127. See chapter 5 in relation to the ODI-F format including setting the TDD (ETQ2)

We welcome the timed windows of April and October for the CSNP-F cost assessment submission, however Ofgem need to provide flexibility as these will be reliant on the timing of the CSNP publication. Based on past experience from the tCSNP1, tCSNP2 and tCSNP2 (re-fresh) timelines are likely to change from the NESO, the windows need to be flexible to accommodate this.

We welcome the continuation of the COAE mechanisms for both the LR projects and CSNP-F however the ASTI approach should be retained which is a COAE threshold set at 5%[229] alongside the flexibility for the licensee to justify an alternative % of a project by project basis. We agree with Ofgem that the COAE needs to be retained alongside the TIM, circumstance in which the COAE can be triggered should align with the ASTI guidance.

[229] ASTI guidance 4.94 https://www.ofgem.gov.uk/sites/default/files/2023-08/Accelerated%20Strategic%20Transmission%20Investment%20Guidance%20And%20Submission%20Requirements%20Document.pdf

Please see our response to ETQ 26 for further comment on PCF.

ETQ 39 Do you agree with our proposed approach to T2/T3 crossover projects?
We welcome the intention that Ofgem "Will ensure that no efficient and justified investment is left unfunded solely due to projects falling between regulatory funding periods", although we seek further detail and agree to work with Ofgem on how this will work in practice, so we can understand the approach and the intention that is going to be taken. Please see our comments within ETQ 29 and 31 which highlight the need for funding adjustment to cover 'crossover' projects that require costs to be incurred in RIIO-ET3 to facilitate delivery in the first or second year of RIIO-ET4. This approach would be consistent with the proposal for the Volume Driver in paragraph 4.108 of the RIIO-3 DD – Electricity Transmission Annex and ensure continuity from RIIO-T3 into RIIO-T4.

Whilst we recognise NARM is not an uncertainty mechanism as listed in this chapter, we raise concerns about an identified funding gap, where a project identified in our non load baseline for RIIO-T2 has incurred significant project delays out with our control and will not be completed in RIIO-T2. We believe that the current regulatory mechanisms would prevent this project being funded when it completes in RIIO-T3 given based on a defined reporting criteria not being achievable. We provide further detail on the treatment of this specific project, SPNLT20109, in our response to OVQ4 in Chapter 16 on NARM. We require Ofgem to set out their policy for the funding of NARM projects across price controls ahead of FD.

ETQ 44 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 have been pro-active in demonstrating that there is a gap in the price control framework for asset interventions whose needs case is not evident at the time of the business plan submissions[230]. We presented a number of scenarios to Ofgem, but the most significant of these have been disregarded without presenting full reasoning. While we agree that the scenario named in the question is valid, it is valid only because the NARM funding and adjustment mechanism is not fit for purpose. For this type of scenario, it is very unlikely that the project will not include NARM assets.

Conversely, in the scenarios which Ofgem has disregarded, those that relate to non-NARM assets, have no route to funding. Necessary works which are clearly in consumers' interests should have their efficient costs funded. By expecting TOs to "manage within their existing baseline allowances" interventions on emerging asset issues, Ofgem will not be providing TOs with the funding required to deliver works that Ofgem has already determined to be justified (i.e. to release baseline allowances for new issues). This is an illogical position further exacerbated in the case of works governed by PCDs where the allowances would be adjusted to remove the allowances associated with undelivered works and therefore could not fund the new works.

The proposal that the Totex Incentive Mechanism (TIM), a mechanism to incentivise efficiency, is used to offset the impact of a failure to provide funding for the efficient costs of justified works in consumers' interests is illogical and inconsistent with the stated purpose and intention of TIM.

ETQ 45 Do you agree with our proposed design of the Non-Load Re-opener?
No, the design of the Non-Load Re-opener fails to address the absence of a funding mechanism for necessary works that are in consumers' interests. Please see our response to ETQ44.

[230] Ofgem Cost Assessment Working Group 18 06/03/2025.

Chapter 7 - Value for Money

7.1 Overview

7.1.1 We broadly support Ofgem's intention to assess the economic impacts of RIIO-3 and welcome the effort to demonstrate value for money. However, we are concerned that the current approach may understate the benefits of the RIIO-3 framework due to the way the counterfactual has been constructed and applied.

7.1.2 Ofgem adopts a "do-minimum" counterfactual—an evolved RIIO-2 framework—on the basis that a "do-nothing"[231] option is not viable and that other alternatives are unrealistic. While it is reasonable to exclude impracticable options, the absence of any modelling or quantification of alternative regulatory paths limits the robustness of the analysis. This is particularly important in the context of Electricity Transmission, where RIIO-3 could enable upwards of £80 billion in investment, compared to £18 billion under RIIO-2[232].

7.1.3 While Ofgem acknowledges that RIIO-2 already included mechanisms such as ASTI and LOTI, RIIO-3 introduces additional funding tools (including CSNP-F, APM, and new load re-openers) that are expected to accelerate investment and reduce the risk of non-delivery of CP2030. These enhancements reflect a strategic shift in the regulatory framework to support a significantly larger investment programme, with RIIO-3 enabling a £32bn increase in totex and £5bn in constraint cost savings compared to the evolved RIIO-2 counterfactual[233].

7.1.4 *"...we focus on areas which we are proposing to change in RIIO-3 and are clear policy choices... For other areas, where there is no policy change, we assume there is no economic impact..." – paragraph 3.4*

7.1.5 Ofgem's stated approach—focusing only on areas where policy changes are proposed and assuming no economic impact where tools remain unchanged—further limits the scope of the analysis. This means that if a mechanism existed in RIIO-2, even in a different form, it is treated as having no incremental impact (e.g. earlier funding, stronger delivery incentives). As a result, the analysis may not fully capture the added value of RIIO-3's enhancements. This limits the scope of spillover benefits that could be attributed to RIIO-3. As a result, the assessment may understate the added value of RIIO-3's enhancements and fail to capture spillover benefits such as improved delivery certainty, reduced financing risk, and better alignment with strategic policy goals like CP2030.

7.1.6 For instance, resilience strategies may follow the same principles, but they are now being implemented in a context of significantly higher investment. Similarly, the innovation framework may be structurally similar to RIIO-2, but the scale of system transformation under CP2030 increases the potential value of innovation deployment. Without adjusting for this shift in context, the assessment may undervalue the real-world impact of continuing these tools under RIIO-3.

7.1.7 While Ofgem's impact assessment does acknowledge some avoided costs, such as reduced constraint payments and lower wholesale electricity prices, it does not fully account for the broader economic and fiscal risks associated with delaying investment in clean energy infrastructure. The recent OBR report highlights that a failure to mitigate climate change — with global temperatures rising by 3°C — could result in an 8% hit to UK GDP by the 2070s and a near doubling of government borrowing, primarily due to lower productivity and employment, which in turn reduces tax receipts[234]

7.1.8 In contrast, the cost of delivering the UK's net zero transition has fallen significantly. The government's required investment has been revised down from 11% to just 6% of GDP over 25 years, largely due to declining costs of clean technologies such as electric vehicles and

[231] RIIO-3 DD Impact Assessment, para 3.1
[232] RIIO-3 DD Impact Assessment, para 3.12
[233] RIIO-3 DD Impact Assessment, para 3.18
[234] OBR: Net-zero is much cheaper than thought for UK – and unchecked global warming far more costly - Carbon Brief

renewables. The net cost to the economy is now estimated at £116 billion — roughly £70 per person per year — a figure that underscores the affordability of early action.

7.1.9 Given this context, Ofgem should seek to quantify (even approximately) the wider economic and customer benefit of accelerated investment enabled by RIIO-3. While we recognise the inherent difficulty in modelling these impacts with precision, excluding them entirely from the benefits package risks understating the full value of the RIIO-3 framework. A more comprehensive assessment would better reflect the strategic importance of timely infrastructure delivery in supporting national climate goals and long-term economic benefits.

7.1.10 Moreover, the OBR's analysis reinforces the point that the benefits of clean energy investment are not static or short-lived — they compound over time. Ofgem's assessment of RIIO-3 in isolation does not capture the cumulative and evolving nature of these benefits. Mechanisms and tools introduced in RIIO-2 that have since matured or expanded in RIIO-3 — and will likely continue to evolve in RIIO-4 and RIIO-5 — should be tracked and quantified to demonstrate how their impact grows over successive price control periods. This would provide a clearer picture of the long-term value and help ensure that the full benefits of the RIIO framework are recognised.

7.2 Customer Bill Impacts

7.2.1 We recognise the value of Ofgem's modelling in providing a central estimate of RIIO-3's impact on consumer bills. We believe the current approach has several important limitations that may lead to an understatement of costs, risks: particularly for certain consumer groups.

Static demand and connection assumptions

7.2.2 We are concerned by the assumption that electricity and gas demand, as well as the number of gas connections, remain flat from 2025/26 onwards[235]. This assumption is unlikely to hold, particularly in light of the UK's net zero targets, the electrification of heat and transport, and the expected decline in domestic gas use.

7.2.3 If gas customer numbers fall, the fixed costs of the gas network will be spread across fewer consumers, resulting in higher per-customer charges than currently estimated. This could disproportionately affect remaining gas users, many of whom may be in vulnerable or hard-to-decarbonise households. The current model does not account for this dynamic, which could significantly affect the cost distributional impact of RIIO-3.

Use of a "typical" dual fuel consumer profile

7.2.4 In addition, the modelling is based on a "typical" dual fuel consumer using 2,700 kWh of electricity and 11,500 kWh of gas annually[236]. While this provides a useful benchmark, it may not reflect the experience of a wide range of consumers, including electrically heated homes with no gas connection and high-usage households, such as those with electric vehicles or heat pumps. These groups may experience significantly different impacts from changes in network charges. Without modelling these variations, it is difficult to assess the cost distributional effects of RIIO-3 across different consumer types.

7.2.5 Moreover, the analysis does not consider the impact on vulnerable consumers, who may be disproportionately affected by increases in network charges—particularly if they are unable to access the benefits of decarbonisation investments such as heat pumps or rooftop solar. Without disaggregated modelling or distributional analysis, it is difficult to assess whether RIIO-3 will exacerbate or mitigate energy inequality.

7.2.6 We support Ofgem's commitment to transparency in assessing the consumer impacts of RIIO-3. However, we believe the current modelling assumptions limit the ability to fully understand the

[235] RIIO-3 DD Impact Assessment, table 5: notes section
[236] RIIO-3 DD Impact Assessment, table 5: notes section

scale of bill impact. A reassessment of these assumptions—particularly around demand, consumer diversity, and system-wide costs will be needed.

7.3 Customer Benefits

7.3.1 We recognise the importance of assessing the economic impacts of RIIO-3 and support Ofgem's efforts to do so. However, the current approach relies too heavily on qualitative claims and third-party submissions; particularly from NGET and SPT[237], the latter supported by consultant Centre of Energy Policy (CEP). While these contributions are valuable, they are not a substitute for independent, regulator-led analysis.

7.3.2 The reliance on individual business plans, especially when not all TOs have provided equivalent estimates, risks skewing the evidence base and undermining the objectivity of the assessment. This could lead stakeholders to question whether the evidence presented is impartial or representative of the sector as a whole.

7.3.3 To strengthen the credibility of the evaluation, we believe Ofgem should undertake its own macroeconomic impact analysis, either internally or by commissioning an independent consultant. This analysis should be based on consistent data across all TOs and apply a transparent and reproducible methodology. The approach taken by us, supported by CEP[238], offers a strong example of best practice. Their modelling provides quantified estimates of GDP uplift, employment gains, and household income effects: metrics that are essential for understanding the broader economic value of RIIO-3 throughout GB as a whole. Ofgem adopting a similar approach would help ensure a fuller and more accurate picture of the framework's economic impact.

7.3.4 Ofgem should translate these macroeconomic benefits into a monetary value that reflects the direct and indirect gains to consumers. While we acknowledge that quantifying such impacts is complex, not doing so risks understating the full benefits package. For example, GDP uplift and increased employment contribute to higher household incomes and improved fiscal sustainability — outcomes that ultimately benefit consumers through lower bills, better service quality, and reduced economic vulnerability. These benefits should be incorporated into the consumer benefits case to provide a more holistic picture of RIIO-3's impact.

7.3.5 In addition, Ofgem rightly acknowledges the environmental significance of RIIO-3, particularly in enabling the decarbonisation of the power sector and supporting the UK's broader net zero goals. However, the current approach to evaluating these environmental benefits remains limited by a lack of quantification.

7.3.6 Ofgem explicitly states within their Impact Assessment that:

> *"given the challenges in directly distinguishing the size of benefits in our proposed approach from the counterfactual, we have not sought to quantify the direct impact of network investment on carbon emissions"[239].*

7.3.7 While it is reasonable to expect that increased renewable generation and reduced reliance on gas will lead to significant emissions reductions, these claims are not currently supported by direct modelling or data. This absence of quantification weakens the evidence base for RIIO-3's environmental claims. Without clear estimates of the emissions reductions enabled by network investments, it is difficult to assess the scale of benefits or compare them to the costs of the planned investments. This also limits the ability to evaluate the cost-effectiveness of RIIO-3 in delivering environmental outcomes or to benchmark progress against national targets.

[237] RIIO-3 DD Impact Assessment para 4.5 and 4.6
[238] How will SP Energy Network's RIIO-T3 Investment Plans Impact the Wider UK Economy?
[239] RIIO-3 DD Impact Assessment, para 4.15

7.3.8 Ofgem should seek to translate these benefits into a monetary value that reflects the direct and indirect gains to consumers. While we recognise that quantifying environmental impacts — such as avoided carbon emissions, improved air quality, and reduced climate-related damages — is complex, excluding them entirely risks understating the full benefits package. For example, emissions reductions contribute to long-term economic resilience, lower health costs, and reduced fiscal exposure to climate-related risks — all of which ultimately benefit consumers. These benefits should be incorporated into the consumer value case to provide a more holistic picture of RIIO-3's impact.

7.3.9 Although Ofgem does provide figures on constraint cost savings (largely driven by connecting renewable generation)[240], these are only indirectly linked to carbon benefits. The emissions reductions associated with reduced reliance on carbon-intensive thermal generation are implied rather than explicitly calculated.

7.3.10 By adopting these measures, Ofgem can provide a more convincing and evidence-based case for the environmental benefits of RIIO-3, aligned with the UK's climate commitments. This would also enhance the overall value-for-money case for the framework by ensuring that both economic and environmental impacts are assessed with rigour and transparency.

7.3.11 Moreover, where benefits may also be understated is in the integration of the energy system. RIIO-3 is designed to support a more flexible, interconnected grid, yet the modelling focuses primarily on direct, monetisable impacts like constraint cost reductions and wholesale price effects. It does not fully capture the potential cost savings and efficiencies that could arise from enhanced system coordination with RIIO-3 investments. For example:

- Flexibility Services: such as demand-side response, battery storage, and smart EV charging, can significantly reduce peak demand, defer costly infrastructure upgrades, and improve system resilience. These services are increasingly central to the energy transition, but their financial impact is difficult to quantify and is not fully reflected in the bill projections.
- Strategic Planning: under RIIO-3, This could lead to better investment decisions, reduced duplication of infrastructure, and more efficient use of resources. However, the benefits of this more integrated planning approach are not explicitly monetised in the assessment.

[240] RIIO-3 DD Impact Assessment, para 4.14

VALUE FOR MONEY QUESTIONS

ETQ 21 What are your views on how TOs could demonstrate 'consumer value' to justify rewards under the Innovative Delivery Incentive?
As noted above in ETQ 20, the arbitrary £10m threshold is set too high across TOs. In our demonstration of consumer value we would expect to submit evidence to show changes in historical behaviour for RIIO-3 quantitative and qualitative analysis to evidence innovations that have had a demonstrable impact on **stakeholders, communities** and consumers. This could be supported by CBA but this may not be possible for qualitative benefits, we would follow best practice in the SiF to determine consumer value.

IAQ1. Do you agree with our approach to assessing the economic impacts of RIIO-3?
We support Ofgem's intention to assess the economic impacts of RIIO-3. However, we are concerned that the current approach may understate the benefits of the framework due to how the counterfactual has been constructed.

While Ofgem acknowledges that RIIO-2 already included mechanisms such as ASTI and LOTI, RIIO-3 introduces additional funding tools (including CSNP-F, APM, and new load re-openers) that are expected to accelerate investment and reduce the risk of non-delivery of CP2030. These enhancements reflect a strategic shift in the regulatory framework to support a significantly larger investment programme, with RIIO-3 enabling a £32bn increase in totex and £5bn in constraint cost savings compared to the evolved RIIO-2 counterfactual.

Ofgem's stated approach—focusing only on areas where policy changes are proposed and assuming no economic impact where tools remain unchanged—limits the scope of the analysis. This means that if a mechanism existed in RIIO-2, even in a different form, it is treated as having no incremental impact (e.g. earlier funding, stronger delivery incentives). As a result, the analysis may not fully capture the added value of RIIO-3's enhancements. This limits the scope of spillover benefits that could be attributed to RIIO-3. As a result, the assessment may understate the added value of RIIO-3's enhancements and fail to capture spillover benefits such as improved delivery certainty, reduced financing risk, and better alignment with strategic policy goals like CP2030.

This assessment does not account for interaction effects between new and existing tools, nor does it adjust for the scale and context in which these tools are now being applied. For example, unchanged mechanisms like resilience and innovation are now operating under much greater investment pressure and system transformation, which could amplify their impact. By not recognising these dynamics, the assessment risks missing the cooperative value of RIIO-3, as we refer to in para 7.1.6.

Ultimately, while the direction of the impact assessment is supported, but we believe the current approach risks understating the full economic value of RIIO-3.

IAQ2. What are your views on the appropriate approach to evaluation of the economic impacts of RIIO-3?
We recognise the importance of assessing the economic impacts of RIIO-3 and support Ofgem's efforts to do so. However, the current approach relies too heavily on qualitative claims and third-party submissions; particularly from NGET and SPT, the latter supported by consultant CEP. While these contributions are valuable, they should complement Independent, regulator-led analysis.

The reliance on individual business plans, especially when not all TOs have provided equivalent estimates, risks skewing the evidence base and undermining the objectivity of the assessment. This could lead stakeholders to question whether the evidence presented is impartial or representative of the sector as a whole.

To strengthen the credibility of the evaluation, we believe Ofgem should undertake its own macroeconomic impact analysis, either internally or by commissioning an independent consultant. This analysis should be based on consistent data across all TOs and apply a transparent and reproducible methodology. The approach taken by us, supported by CEP, offers a strong example of best practice. Their modelling provides quantified estimates of GDP uplift, employment gains, and household income effects: metrics that are essential for understanding the broader economic value of RIIO-3 throughout GB as a whole. Ofgem adopting a similar approach would help ensure a fuller and more accurate picture of the framework's economic impact.

Ofgem should translate these macroeconomic benefits into a monetary value that reflects the direct and indirect gains to consumers. While we acknowledge that quantifying such impacts is complex, not doing so risks understating the full benefits package. For example, GDP uplift and increased employment contribute to higher household incomes and improved fiscal sustainability — outcomes that ultimately benefit consumers through lower bills, better service quality, and reduced economic vulnerability. These benefits should be incorporated into the consumer benefits case to provide a more holistic picture of RIIO-3's impact.

On the environmental side, although Ofgem recognises RIIO-3's role in supporting decarbonisation and net zero goals, its current evaluation lacks quantification. Ofgem admits it has not attempted to measure the direct emissions impact of network investment. This omission weakens the case for RIIO-3's environmental benefits, as it becomes difficult to assess the scale of emissions reductions or compare them to the costs involved. While constraint cost savings are presented (largely from connecting renewables) the associated carbon benefits are only implied, not calculated.

Ofgem should seek to translate these benefits into a monetary value that reflects the direct and indirect gains to consumers. While we recognise that quantifying environmental impacts — such as avoided carbon emissions, improved air quality, and reduced climate-related damages — is complex, excluding them entirely risks understating the full benefits package. For example, emissions reductions contribute to long-term economic resilience, lower health costs, and reduced fiscal exposure to climate-related risks — all of which ultimately benefit consumers. These benefits should be incorporated into the consumer value case to provide a more holistic picture of RIIO-3's impact.

Moreover, where benefits may also be understated is in the integration of the energy system. RIIO-3 is designed to support a more flexible, interconnected grid, yet the modelling focuses primarily on direct, monetisable impacts like constraint cost reductions and wholesale price effects. It does not fully capture the potential cost savings and efficiencies that could arise from enhanced system coordination with RIIO-3 investments. For example:

- Flexibility Services: such as demand-side response, battery storage, and smart EV charging, can significantly reduce peak demand, defer costly infrastructure upgrades, and improve system resilience. These services are increasingly central to the energy transition, but their financial impact is difficult to quantify and is not fully reflected in the bill projections.
- Strategic Planning: under RIIO-3, This could lead to better investment decisions, reduced duplication of infrastructure, and more efficient use of resources. However, the benefits of this more integrated planning approach are not explicitly monetised in the assessment.

IAQ3. Do you agree with our approach to modelling the bill impacts of RIIO-3? Please provide any additional effects or alternative measures that you think would be appropriate.
The assumption that electricity and gas demand, as well as the number of gas connections, remain flat from 2025/26 onwards. This assumption is unlikely to hold, particularly in light of the UK's net zero targets, the electrification of heat and transport, and the expected decline in domestic gas use.

If gas customer numbers fall, the fixed costs of the gas network will be spread across fewer consumers, resulting in higher per-customer charges than currently estimated. This could disproportionately affect remaining gas users, many of whom may be in vulnerable or hard-to-decarbonise households. The current model does not account for this dynamic, which could significantly affect the cost distributional impact of RIIO-3.

In addition, the modelling is based on a "typical" dual fuel consumer using 2,700 kWh of electricity and 11,500 kWh of gas annually. While this provides a useful benchmark, it may not reflect the experience of a wide range of consumers, including electrically heated homes with no gas connection and high-usage households, such as those with electric vehicles or heat pumps. These groups may experience significantly different impacts from changes in network charges. Without modelling these variations, it is difficult to assess the cost distributional effects of RIIO-3 across different consumer types.

Moreover, the analysis does not consider the impact on vulnerable consumers, who may be disproportionately affected by increases in network charges—particularly if they are unable to access the benefits of decarbonisation investments such as heat pumps or rooftop solar. Without disaggregated

modelling or distributional analysis, it is difficult to assess whether RIIO-3 will exacerbate or mitigate energy inequality.

We support Ofgem's commitment to transparency in assessing the consumer impacts of RIIO-3. However, we believe the current modelling assumptions limit the ability to fully understand the scale of bill impact. A reassessment of these assumptions—particularly around demand, consumer diversity, and system-wide costs will be needed.

ETQ 67 Do you have any views on our engineering assessment of the thematic issues we have identified?
The assessment is generally fair with respect to our engineering submissions. Given Ofgem's positive feedback on our EJPs, we are surprised at the extent of disallowances for some other elements of the cost assessment. We offer commentary on optionality and fast tracking in our responses to subsequent questions.

ETQ 68 Do you agree with our approach to maintaining future optionality through ensuring licensees use extendible designs?
Our entire approach to scheme development has integrated this approach for some time and this is evident in our RIIO-T3 business plan. The criticism implicit in paragraph 5.167 is not reflective of our designs.
We have significant concerns regarding the reference to the Electricity Transmission Design Principles (ETDPs) in this context. The purposes of the ETDPs are set out in the Electricity Networks Commissioner's (ENC) report and the Transmission Acceleration Action Plan (TAAP). These are:

- "A public document detailing the principles and methods used to design the system and decide the configuration of assets; onshore or offshore, overhead or underground" (ENC8) and
- "Electricity Transmission Design Principles (ETDP) should be created to provide greater clarity on the type of asset to be used in different environments" (TAAP RD1); "Engagement with communities hosting transmission infrastructure should be focused on the choices that they can influence within the ETDP design principles and guidelines" (TAAP RD2)

The ETDPs are not a tool to manage regulatory approvals. Were the drafting of the principles to be directed at this purpose, it would represent a significant risk to their effectiveness and could undermine the ENC and TAAP objectives. The proposal to fast-track projects that follow the principles and further scrutinise those that do not is illogical when viewed against the purposes and objectives of the principles. They are not a set of standards, they are, as the name suggests, a set of principles which explain "the principles and methods used to design the system" and "provide greater clarity on the type of asset to be used in different environments". All projects proposed by us will, therefore, follow the principles.

SPTQ 8 What are your views on our engineering assessment of SPT's RIIO-ET3 Business Plan?
Ofgem's assessment reflects the high standard of our submission. However, we note that Annex 1 lists 5 EJPs/OSRs but 5.12 notes that 7 EJPs are not fully justified due to their proposed use of GIS and we would welcome clarification on this point. With regard to the five EJPs in Annex 1, only Gala North 400/132kV substation proposes the use of GIS. In the other four cases the EJPs state clearly that the switchgear technology will be determined following further development. We welcome the award of Pre-Construction Funding to enable this development work.
With regard to Gala North, we note the general comments in 5.7 regarding further considerations and clarity and refer again to the site selection information provided in the EJP and our response to SPEN034 which define the specific circumstances of this particular site. Further, as explained to Ofgem on numerous occasions, we do not propose developments on a portfolio basis. We undertake detailed optioneering on a project specific basis, considering all of our statutory duties. We will continue to provide this evidence in future submissions.

Chapter 8 - Real Price Effects

8.1 Overview

8.1.1 In our Cost Assessment Annex supporting our Business Plan, we set out our views on the RIIO-T2 approach in developing the RPE mechanism. At a high-level, this involved:

- Using more granular material indices
- Consideration of more specific labour indices and attempt to a line to a greater extent with the weights of the costs we face

8.1.2 We commissioned Oxera to again assess the RPE proposals (Annex 4.1[241]) as well as the ongoing efficiency (Chapter 9) proposed by Ofgem, and to evaluate the usefulness of the DD RPEs for the ET sector and us in particular.

8.1.3 As we have previously set out, in RIIO-T3, SPEN will likely face increased input price pressures. In addition to economy-wide input price pressures (e.g. real wage growth), electricity networks across the UK and more globally are increasing their activity in order to meet the needs of the energy transition, this can lead to capacity constraints having an impact on our suppliers, and may lead to increased costs for us. These capacity constraints relate to highly specialist goods and services, which are central to SPEN's work, but are unlikely to be captured by the 'broad' input price indices that were used at RIIO-2.

8.1.4 As such, Ofgem's decision to largely maintain the RIIO-2 approach to accounting for RPEs at RIIO-3 is concerning. We identified two key risks with this approach in our business plan submissions:

- Basis risk—the input price indices are overly broad and do not capture the price pressures that we actually face, particularly for specialist goods and services (e.g. specialist labour, transformers, cables).
- Composition risk—weights relating to each input price index are fixed ex ante, such that if a company spends more or less on a particular input, this is not reflected in the RPE adjustment.

8.1.5 Ofgem has not adequately engaged with our concerns relating to the RIIO-2 mechanism[242] or adequately engaged with our previous proposed corrections to the RPEs mechanism. Given the significant concerns we raised, we expected more meaningful engagement on this issue and more fundamental amendments to the RIIO-2 mechanism.

8.1.6 Below, we outline why Ofgem's approach does not correct for the basis and composition risks, as well as provide recommendations for what is required to make these mechanisms useful at reflecting cost pressures.

8.2 Basis risk

8.2.1 Basis risk relates to the observation that the input price indices that Ofgem uses for the RPE mechanism do not track the input prices that SPEN (and other TOs) ultimately face. This is driven by the following factors.

- TOs use different inputs to those that are captured in the input price index. For example, the 'FOCOS Resource Cost Index of Infrastructure: Materials FOCOS' index captures prices for all infrastructure projects. It is possible that the materials used to construct roads, railways and bridges (for example) are different to the materials used to construct cables and transformers, and may therefore be subject to different input price pressures.
- TOs utilise highly specialised inputs which are either not captured in the input price indices utilised or form a small component of those indices. In RIIO-3, both the UK networks and several European networks will be increasing activity in order to enable the

[241] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*
[242] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. p44

energy transition[243]. This may place significant capacity constraints on SPEN's suppliers, resulting in increased input price pressures (e.g. increased supplier margins) that are not captured in the input price indices.

- Ofgem has applied a materiality threshold. This prevents Ofgem from applying more targeted (and more accurate) input price indices, such as input price indices for individual assets that SPEN purchases (e.g. cables, transformers). It also means that we receive less protection from input price pressures than NGET and SHET.

8.3 Composition risk

8.3.1 The RPE mechanism imposes weights on each input price index, based on either a notional cost structure (for gas distribution networks) or the cost structure submitted in companies' business plans (for TOs). These weights for each of these price indices are fixed throughout RIIO-3. Therefore, even if individual input prices tracked the input price pressures that companies face (i.e. there is no basis risk), we (and other TOs) could still be exposed to composition risk if the outturn input mix differs to what Ofgem has/had assumed.

8.3.2 If TOs were in a steady state environment, then we could expect that the RPE indices (assuming they were well calibrated in the first instance) and the weights applied to these could largely expect to be reflective of costs the TOs face, However, the ET sector in particular is not in a predictable, steady-state environment. TOs are required to scale up (or down) investments over RIIO-3 in order to cope with changing priorities[244]. This is apparent from the significant amount of expenditure that Ofgem has allocated to uncertainty mechanisms (if these costs were easily predictable, we may expect them to be captured within ex ante allowances). This composition risk, given the change to the investment environment (i.e. it is not a steady state environment) could raise risk to companies and consumers

8.4 Recommendations

8.4.1 In the Oxera's supporting document for our business plan submission, they provided detailed recommendations for how the RPE mechanism could be improved, addressing both basis risk and composition risk[245]. We consider that these recommendations remain relevant and should be implemented for the RIIO-3 Final Determination, if feasible.

8.4.2 However, we note that such a wholesale change to the RPE mechanism may be difficult at this stage, given the time constraints and the need for industry-wide consultation. As such, we consider that the following simple corrections could be made as a minimum.

- **First**, Ofgem should maintain or enhance the stepped TOTEX incentive mechanism (TIM) in order to protect companies and consumers from changes in input prices that are not captured by the RPE indices. However, the TIM is a 'blunt instrument' for accounting for RPEs, and a more targeted approach to addressing the specific risks associated with input price pressure is required.
- **Second**, the materiality threshold should be reduced (or removed) and a consistent set of RPEs should be applied for all companies. While it may be disproportionate to develop price indices for immaterial cost lines, Ofgem has already constructed a price index for plant and equipment for NGET and SHET. Therefore, applying the same RPE to SPEN would not increase any administrative effort.
- **Third**, a relevant, targeted RPE index should be developed for uncertainty mechanisms, where appropriate. For example, the unit rates attached to installing new lines and transformers could be indexed to price indices for lines/cables and transformers, respectively. This would help to mitigate the composition risk.

[243] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. p44
[244] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. p47
[245] SP Energy Networks. (2024). *Cost Assessment and Benchmarking Approach (including RPEs & OE) RIIO-T3 Business Plan SP Energy Networks*. p67

RPE QUESTIONS

OVQ 18 Do you agree with our proposed approach to RPEs?
No, we do not agree with the approach, as we find that many of the issues that we had previously raised in our Business Plan relating to the RPEs mechanism have not been addressed. In this context, Ofgem's decision to largely maintain the RIIO-2 approach to accounting for RPEs at RIIO-3 is concerning. We identified two key risks with this approach in our business plan submissions.

1 Basis risk—the input price indices are overly broad and therefore do not reflect the price pressures that we actually face, particularly for specialist goods and services (for example specialist labour, transformers, cables).

2 Composition risk—the weights attached to each input price index are fixed on an ex ante basis, such that if a company spends more or less on a particular input, this is not captured in the RPE mechanism.

Our concerns stemming from these risks continue as Ofgem has not adequately engaged with our concerns relating to the RIIO-2 mechanism, or with our proposed corrections to the mechanism. Given the significant concerns raised, we would have expected more meaningful engagement on these issues and appropriate levels of amendments made to the RIIO-2 mechanism. If the changes outlined in our business plan submissions cannot be implemented (e.g. due to time constraints, need for consultation), we consider that the following simple corrections could be made at a minimum.

- Maintain or enhance the stepped TIM proposed at the DD in order to protect companies and consumers from changes in input prices that are not captured via the RPE indices.
- Remove the materiality threshold and apply a consistent set of RPE adjustments for all companies.
- Apply a relevant, targeted RPE index to uncertainty mechanisms where appropriate. For example, the unit rates attached to installing new lines and transformers could be indexed to price indices for lines/cables and transformers, respectively.

Chapter 9 - Ongoing Efficiency

9.1 Overview

9.1.1 In line with previous regulatory reviews, Ofgem has proposed to utilise a 1% OE as part of their challenge for SPEN's ex ante allowances. This is higher than the ambitious 0.4% that SPEN put forward in our Business Plan, and significantly outside of the reasonable range set out in Oxera's "Ongoing efficiency and real price effects" annex which suggested a 0.0%-0.5% OE range per annum.

9.1.2 It would appear based on the evidence provided that Ofgem's report that their work started with the 1% pa ambition, and attempted to collect supporting evidence for that 1% per annum position[246], rather than the OE estimate being the conclusion based on empirical analysis. Ofgem has commissioned Grant Thornton to carry out a critical analysis.

9.1.3 There are a number of issues with Grant Thornton's analysis, which include:

9.2 Choice of productivity measure

9.2.1 Grant Thornton suggests that "value added" (VA) measures should be part of the estimation of total factor productivity. As set out in Oxera's "Ongoing efficiency and real price effects" Business Plan supporting document[247], we believe that gross output (GO) estimations are more all encompassing, and therefore should be considered in isolation.

9.2.2 VA measures, suffer from not being good proxies for a measure of technology shifts, ignore intermediate inputs (therefore not measuring productivity improvements at TOTEX level), and have a known upward bias (in the role of technological progress on delivery productivity improvements).

9.2.3 As such, consideration of VA creates a flaw in the estimation of a reasonable measure of OE.

9.3 Selection of comparators

9.3.1 Grant Thornton's analysis uses industries which are not relevant/similar to the ET sector as a proxy for expected productivity levels in the ET sector, and applies an implicit equal weighting to these industries when estimating an average growth. This, most materially, includes Grant Thornton considering elements of the telecommunications sector (Information and Communication – henceforth I&C) - an industry that despite containing elements of regulated utilities, bears little to no similarity to the ET sector from a growth perspective.

9.3.2 Assuming the decimal places from the Grant Thornton analysis are exact numbers (to nearest decimal), we get to the following estimations of the OE calculation pre and post-removal of I&C.

[246] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. page 2.
[247] Oxera. (2024). *Ongoing efficiency and real price effects*. p4

Table 9-1 - Comparison of Ofgem's Ongoing Efficiency Calculation (with and without Information and Communication)

	1970–96	1997–2007	2010–19	1970–2019 (excl. 2008 and 2009)
Simple average	0.5	1.3	0.1	0.7
Simple average (excl. Information and Communication)	0.4	0.6	-0.3	0.3

Source: Oxera analysis of Grant Thornton (2025), 'Independent Report on Ongoing Efficiency: RIIO-3 Technical Annex', June, Table 2.

9.3.3 Even if the inclusion of I&C was appropriate, all industries are implicitly given an equal weight in Grant Thornton's analysis, rather than assigned a weight based on perceived relevance of the sector. Oxera's analysis conversely provided 3 scenarios[248], the third (broad) suggested multiple industries with assigned weights based on relevance. Having weights based on the relevance of the industry means that any ongoing efficiency stemming from this assessment is more likely to be reflective of feasible OE in the ET sector, than a simple average as Grant Thornton use.

9.4 Time period of their analysis

9.4.1 Grant Thornton use a very long-term view (for productivity purposes) in their analysis and remove both the Great Recession, and also the Covid pandemic from their analysis, while capturing the high productivity growth period of 1997-2007[249]. Capturing high growth periods while treating low/negative growth periods as outliers and therefore removing them, knowingly biases upwards the estimates of OE.

9.5 Selection of their point estimate

9.5.1 Grant Thornton in their analysis appear to defer largely to Ofgem to select a point estimate, which they set at 1% pa. This point estimate is not clearly supported by good data.

9.5.2 In support of a higher estimate of OE Grant Thorton have relied on the following flawed concepts:

- **Embedding technological advance**

9.5.3 Grant Thornton utilise qualitative arguments in favour of a higher than midpoint estimate from their own analysis, and those qualitative arguments are not supported by quantitative evidence.

- **Weight on VA**

9.5.4 As above, reliance on VA provides the opportunity for upwardly biased estimates of OE.

- **IT and digitalisation**

9.5.5 Grant Thornton's analysis suggests that there is scope for IT and digitalisation to aid in SPEN obtaining more ambitious (implicitly) OE through intelligence of the network, and therefore the ability for the TOs to make the network more efficient. This, while intuitively reasonable suffers from the following issues:

  - IT and digitalisation is already within the I&C estimate, so cannot be used (reasonably) as grounds for aiming up OE

[248] Oxera. (2024). *Ongoing efficiency and real price effects*. Table 2.1
[249] Grant Thornton. (2025). *Independent Report on Ongoing Efficiency*. page 5

- The ET sector is less IT intensive than comparator sectors, and where similar industries exist to ET, their productivity estimates already capture their inherent improvements in productivity due to IT adoption etc.
- Even where productivity improvements stem from IT/digitalisation, it may not necessarily lead to a cost reduction

- **Consideration of GFC period**

9.5.6 There has been a marked productivity decline since the Global Financial Crisis (GFC), and Ofgem's previous assertion that energy networks are unaffected by economy-wide shutdowns in productivity are largely unfounded.

- **Ambition of company business plans**

9.5.7 Embedding the concept of "ambition" within regulatory frameworks around OE can be inherently flawed from the perspective that it can create perverse incentives around the way firms consider penalties/rewards around the overall financial package[250].

- **Regulatory precedent**

9.5.8 While we accept that there is some harmony among regulators for setting OE at 1% in some areas, this does not mean that on an enduring basis that 1% pa is reasonable. We also note that there are other examples elsewhere where OE, or its equivalent is not equal to 1%, such as elsewhere in Europe, and Oxera highlight[251] that there are multiple precedents[252] for a different OE target, with *most being under 1%*[253]. Regulatory precedent should not be used as a basis for the result. Regulatory precedent should be used as a guide for the methodology, where the ultimate result is then driven by data and evidence.

9.6 Independent forecasts of economy-wide productivity

9.6.1 Oxera suggest that official forecasts (OBR/BoE etc.) do not support an OE of 1% pa[254].

9.6.2 Based on an updated version of the EU KLEMS, which had, according to Oxera's pre-Business Plan analysis proposed a feasible OE range of 0.0%-0.5% (which SPEN cited in our Business Plan), that same range would now be -0.7%-0.2%[255], suggesting that even our 0.4% estimate from our Business Plan may now be higher than appropriate economic evidence would justify. We do not therefore, support the use of the 1% OE figure that Ofgem has proposed in the DD.

[250] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. page 6.
[251] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. page 32.
[252] This assessed regulatory regimes inter alia in the Netherlands (ACM), Walloon region of Belgium (Commission wallonne pour l'Energie, CWaPE), Austria (E-Control) and Finland (Energiavirasto).
[253] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. page 32
[254] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. section 2.2.5.
[255] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs.*

ONGOING EFFICIENCY QUESTIONS

OVQ 19 Do you agree with our proposed approach to ongoing efficiency?
No, Ofgem's 1% OE estimate is not supported by a proper assessment of reliable evidence and it appears that it has largely ignored the cross industry analysis we set out as part of our Business Plan which observed a 0.0%-0.5% range, within which, we proposed an ambitious target of 0.4%. Ofgem has used in its analysis a very long time horizon which is an inaccurate proxy for modern productivity growth; relies on the Information and Technology sector as a comparator which bears little relation to the operations of the ET sector; and has inappropriately relied on a qualitative argument around technological advances to propose their estimate of 1%.

The primary basis for the higher estimate of 1% seems to be a similarity drawn between the 1997-2007 period, which for recent history had high levels of productivity, and the expected growth coming from AI and emerging technologies. This similarity is not borne out by quantitative evidence and appears to be a reason provided for an otherwise historical average that is far below the 1% figure Ofgem has cited in previous regulatory controls. As such, Ofgem has inappropriately utilised Grant Thornton's analysis to develop a range for their OE range which is too high (based on inappropriate comparators) and then implicitly (through greater weight provided to a high productivity period) suggests that the OE should be more in line with a high-productivity period (1997-2007) due to an unjustified assertion on the similarity of the expected productivity due to technological advance.

Several arguments Ofgem and Grant Thornton use to justify a stretching target were already predicted and addressed in our business plan submission,[256] yet Ofgem has not engaged or responded to the evidence presented in our business plan, and has failed to take account of these points in reaching its provisional OE assessment in the Draft Determination. These include:

- Suggesting that total factor productivity (TFP) may not account for embodied technical change[257]
- Observing value added (VA) measures lead to higher estimates of productivity growth than gross output (GO) measures[258]
- IT and digitisation expenditure activities impact on productivity growth[259]
- Innovation funding effect on productivity growth[260]
- The expectation that Ofgem would have removed the telecommunications sector as a reasonable comparator[261] (Grant Thornton consider this, and this inflates the OE estimate);
- the impact of the material slowdown in productivity growth after the financial crisis[262]
- Using the targets proposed by companies being used as a 'lower bound' regarding what the OE target should be (addressed in section 2.7.3 of Oxera's annex).

Utilising more recent EU KLEMS data and excluding irrelevant data (i.e. not using Information and Communication as a comparator industry) suggests that our estimate of 0.4% made in our Business Plan may now be higher than is justified by more recent evidence. As Oxera set out in their up-to-date feasible OE range, this may now be around -0.7%-0.2%[263]

[256] See Oxera (2024), 'Ongoing efficiency and real price effects', December, https://www.spenergynetworks.co.uk/userfiles/file/Oxera-Ongoing-Efficiency-and-Real-Price-Effects.pdf.
[257] Oxera. (2024). *Ongoing efficiency and real price effects*. section 2.7.2
[258] Oxera. (2024). *Ongoing efficiency and real price effects*. section 2.3
[259] Oxera. (2024). *Ongoing efficiency and real price effects*. section 2.7.5
[260] Oxera. (2024). *Ongoing efficiency and real price effects*. section 2.7.1
[261] Oxera. (2024). *Ongoing efficiency and real price effects*. pages 37-39
[262] Oxera. (2024). *Ongoing efficiency and real price effects*. section 2.4.2
[263] Annex 4.1. Oxera. (2025). *4.1 Oxera Ongoing efficiency and RPEs*. page 43

Chapter 10 - Business Plan Incentive

10.1 Overview

10.1.1 We welcome Ofgem's confirmation that we passed Stage A of the BPI and met all minimum requirements. However, we have significant concerns regarding the Stage B and C assessments.

10.1.2 At Stage B, we believe Ofgem's reliance on flawed historical benchmarking models—particularly in assessing CAI and BSC costs—combined with arbitrary weightings for different elements of the analysis fails to reflect the step change required for RIIO-T3 investment and results in an unjustified penalty. There is an inconsistency between areas where Ofgem has applied forward-looking analysis such as insurance and the ratio/ trend analysis for indirects where we perform well and the flawed historical analysis where we are found to perform poorly. We note we have been rewarded or kept neutral for 13 categories of bespoke costs which were subject to a more rigorous and detailed engineering assessment with a £3.8m reward overall. This contrasts sharply with the £3.16m penalty applied to comparatively assessed costs, undermining the robustness and consistency of the process. We urge Ofgem to adopt improved, growth-reflective methodologies for comparative cost benchmarking that place more focus on forward looking assessment. Ofgem must also address the limitations in its bespoke analysis for IT&T, Operational Technology and Cybersecurity which have resulted in poorly justified reductions to allowances as well as BPI penalties.

10.1.3 At Stage C, we are pleased that our business plan received a strong overall rating, with an 'outstanding' score for layout and structure. Nonetheless, we are concerned that the qualitative evaluation of 'Clarity' has been disproportionately affected by isolated errors, without sufficient recognition of the innovative steps we took to enhance transparency, accessibility, and engagement—particularly through public disclosures, stylised diagrams, and stakeholder-friendly materials.

10.1.4 We also strongly disagree with the penalty applied under the "Infrastructure fit for a low-cost transition to Net Zero" outcome. This fails to recognise the wider context of policy uncertainty and the appropriate use of regulatory mechanisms such as ASTI, LOTI, MSIP, and the Load Re-opener to deliver consumer value responsibly. Our EJPs for Load Re-opener projects were based on full optioneering and have been approved by Ofgem.

10.1.5 Finally, in response to comments regarding the absence of an implementation plan for our Business Carbon Footprint (BCF) reduction target, we have now submitted a full implementation plan. We hope this will give Ofgem the confidence needed to reassess our score under Business Plan Commitments and reflect the ambition and credibility of our Net Zero strategy.

BUSINESS PLAN INCENTIVE QUESTIONS

OVQ 11 Do you agree with the equal weightings applied per criteria/rating for the 'Clarity scorecard' and the 'Business Plan Commitments scorecard' for the Stage C assessment?
Yes, we agree with the application of equal weightings across the five criteria in the *Clarity scorecard*. In our view, each criterion requires an equivalent level of effort and attention to meet the expected standard.

However, we do not support the use of equal weighting for the *Business Plan Commitments scorecard*. We believe that the *Deliverability* criterion warrants a higher weighting, as it involves additional complexity in assessing the practicality and feasibility of implementing the commitments made. The remaining three criteria—*Consumer value and additionality*, *Stretching performance*, and *New company proposals*—should, in our view, be equally weighted.

OVQ 12 Do you agree with the weightings applied per outcome for each sector for use in the Stage C - Business Plan commitments assessment?
Yes. The weightings are an appropriate reflection of the priorities in each sector.

OVQ 13 Do you agree with the use of a default materiality threshold and its level?
Yes, we support Ofgem's position that re-openers should be used judiciously and that companies should be expected to manage a degree of cost risk. Setting a materiality threshold is a sensible approach to ensuring this balance. We agree with the proposed threshold of 0.5% of annual ex-ante base revenue (equivalent to £3.7 million for us, based on the Draft Determinations) and encourage Ofgem to maintain its current practice of allowing companies, in appropriate circumstances, to aggregate smaller amounts that individually fall below the threshold.

SPTQ 3 Do you agree with our view that SPT passed all of the minimum requirements and as such are considered to have passed Stage A of the BPI?
We agree with Ofgem's assessment that we have met the minimum requirements, as set out in the Business Plan Guidance, and have passed Stage A of the BPI. Each of our annexes contains a table that signposts readers to where content required in the Business Plan Guidance can be found.

SPTQ 4 Do you agree with our assessment results for SPT against Stage B of the BPI?
We agree with Ofgem that having accurate and ambitious business plans is essential to its role as a regulator. In order for the BPI to incentivise this, it is imperative that the assessment is carried out fairly across network companies and this means it must be based on an accurate reflection of the TOs' costs. However, Ofgem's DD assessment of 'comparatively assessed' costs in Stage B relies on flawed analysis in the cost benchmarking such as the inclusion of a statistically insignificant time trend for CAI, the reliance on just one regression model (Model 1) for BSC, and an arbitrary 50:50 weighting between the historical regression analysis and the forward- looking ratio/trend analysis.
We note that there is a lack of consistency between Ofgem's assessment of 'comparatively assessed' costs (i.e. costs that are subject to benchmarking) and 'bespoke costs' (i.e. costs that are subject to a more detailed engineering assessment). The table below shows the BPI reward/penalty for the two different types of costs.

Table 10-1 - Stage B rewards and penalties

Company	Reward/penalty for comparatively assessed costs	Reward/penalty for bespoke costs
SPEN	-3.16	3.81
NGET	7.14	-1.41
SHET	-1.71	-0.93

Source: Ofgem (2025), 'RIIO-3 DD Overview Document', July, p.55.

In essence, Ofgem has set a significant penalty for comparatively assessed costs, and a significant reward for bespoke costs. This implies that SPEN are assessed to be efficient when Ofgem undertakes a deep dive into the evidence supporting our expenditure proposals which we strongly agree with. But inefficient when Ofgem relies on high-level benchmarking models with flawed elements which we strongly disagree with. We consider that the deep dive assessment is, by its more rigorous nature, more likely to produce an accurate view of our expenditure proposals. This then raises significant questions about the validity and appropriateness of Ofgem's historical benchmarking models which fail to account for the growth that will be required in RIIO-ET3 to meet the government's CP2030. Subsequently facing undue penalties as a further consequence also results in double jeopardy due to poorly justified and flawed elements of the cost assessment.

Furthermore, in the evaluation of comparatively assessed costs, we note the material difference in performance and subsequent rewards/penalties depending on the method used to benchmark. Specifically, SPEN performs poorly across CAI and BSC which are 50% assessed using regression models based on historical data which inadequately accounts for growth. However, SPEN performs comparatively well on categories that apply a more forward-looking analysis, such as the ratio benchmarking in the assessment of insurance costs (bps reward of 0.18). We are also considered to be more efficient in indirect costs that apply more forward-looking analyses. Therefore, we consider Ofgem's assessment of indirect costs via its historical regression analysis underrepresents the significant step change in forecast investment programme and the related significant growth in indirects - particularly for the Scottish TOs. This approach risks distorting comparative cost assessment, as it anchors half the evaluation to past conditions that do not reflect the scale or pace of the investment now required.
In order for there to be a more accurate assessment of costs and consequently a fairer overall assessment under of us in Stage 2 of the BPI it is essential that Ofgem implements alternative approaches for CAI and BSC costs which fully reflect the required growth of our network and the growth in indirect resources required to enable this ensuring all TOs are compared on a level playing field for the BPI.

SPTQ 5 Do you agree with our assessment results for SPT against Stage C of the BPI?
Overall, we welcome the positive aggregate outcome of Ofgem's Stage C BPI assessment. However, we do not agree with several of the underlying judgments, which in our view do not fairly or proportionately reflect the strength of our RIIO-ET3 Business Plan.

In particular, we believe Ofgem's assessment of *Clarity* has relied too heavily on isolated examples, rather than considering the quality and coherence of the full submission and the novel steps we took to make technical content transparent and accessible. Likewise, we strongly disagree with the penalty applied under *Business Plan Commitments (Infrastructure fit for a low-cost transition to Net Zero)*, which overlooks the context of regulatory uncertainty and our agile use of re-opener mechanisms to progress projects.

We are also concerned that Ofgem has not fully recognised the ambition and detail of our commitments under *Business Plan Commitments* (*High quality of service from regulated firms)*. Our workforce, diversity, website accessibility, tax transparency, CP2030 and SO:TO ODI-F commitments all represent bold, measurable and sector-leading steps that go significantly beyond business-as-usual. We have also gone further than other TOs in demonstrating the wider economic impact of network investment through our partnership with the University of Strathclyde's Centre for Energy Policy.

In addition, we note Ofgem's comments on the absence of an implementation plan for our Business Carbon Footprint reduction commitment. This reflected our understanding of the guidance and our prior ED2 experience. Nevertheless, we have now submitted a full, Planet Mark-accredited Net Zero Transition Plan to provide assurance on deliverability.

Finally, we are disappointed that Ofgem is considering adopting our proposed stepped Totex Incentive Mechanism within the DD for generation and demand connections, yet overlooks our role in bringing forward this progressive and consumer-focused regulatory innovation.

Taken together, these examples demonstrate that our Business Plan is more ambitious, transparent, and forward-looking than Ofgem's Stage C scoring suggests. We therefore urge Ofgem to reconsider its evaluation and reflect more appropriately the quality, innovation and consumer benefit embedded within our submission.

Clarity

We note Ofgem's assessment of our business plan as *'acceptable'* in four out of the five evaluation areas, with an *'outstanding'* rating awarded for *'layout and structure'*. While we appreciate the rationale provided for the outstanding rating in that area, Ofgem does not appear to have clearly linked its judgments for the remaining four assessment areas to the specific criteria outlined in the scorecard.

We are concerned that the qualitative assessment lacks a holistic view of the plan, instead relying on selective examples that may have disproportionately influenced the overall scoring. This approach risks misrepresenting the quality and coherence of the full submission and falls short of providing a balanced and comprehensive evaluation of the business plan we delivered.

To support a clearer understanding of Ofgem's assessment we would welcome greater transparency in the FD, specifically with regard to the rationale behind the ratings of *'acceptable'* for the four areas in question.

Separately, on the issue of transparency, we have made the vast majority of our Business Plan documentation publicly available (with minimal redactions), allowing a broad spectrum of stakeholders to engage with and understand our proposals. For example, other TOs have refrained from publishing EJPs due to competition risks or community backlash- however we believe we need to be transparent as possible with all stakeholders and took the commercial risks to publish as much information as possible. We have not observed this same level of openness across the sector and are disappointed that our transparency has not been positively reflected in the assessment of *'Clarity'*.

We believe we have gone significantly further than required in this submission—both in the presentation of the mandated suite of documents and in the inclusion of supporting materials such as stylised circuit diagrams (designed in the style of tube maps), innovative bitesize explainer videos, and a Business Plan summary document—all aimed at improving accessibility and clarity for all stakeholders[264].

In light of this, we respectfully consider that a score of 1.4 basis points under *Clarity* does not accurately reflect a fair and proportionate assessment of the quality and transparency of our submission and ask Ofgem to reconsider a higher score for FD.

Business Plan Commitments

Outcome: Infrastructure fit for a low-cost transition to net zero

We strongly disagree with Ofgem's decision to impose a penalty on us for bringing forward only one project over £29 million for inclusion in the RIIO-ET3 baseline. Ofgem's rationale—that this reflects a 'failure' by SPT and causes consumer detriment—does not reflect the full context, the regulatory framework, or the evidence Ofgem itself has reviewed and approved.

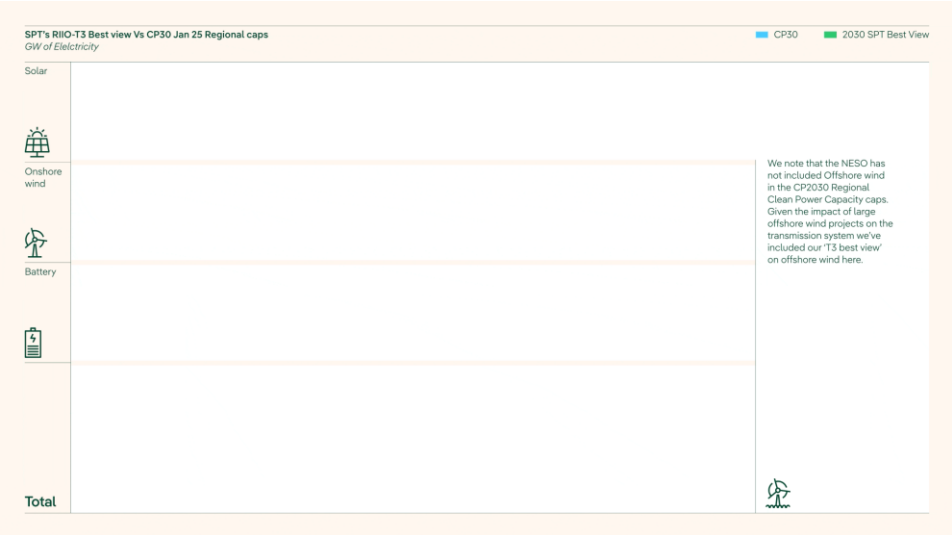
CP2030: Policy and Regulatory Uncertainty Recognised by Ofgem

Ofgem acknowledges in both its RIIO-ET3 DD[265] and its SSMD[266] that TOs have been operating under significant and ongoing uncertainty. The UK Government's Clean Power 2030 (CP2030) policy, NESO's connection reform programme, and the development of the SSEP have had substantial and ongoing implications for the certainty of future load-related transmission investment needs.

[264] For example Scottish Renewables responded to Ofgem's call for evidence stating: "Stakeholder-led, SP Energy Network's RIIO-T3 Business Plan sets out a clear and evidence-based need for an expected known total expenditure of £10.6 billion over the RIIO-T3 period". - Scottish Renewables response."
[265] RIIO-3 DD – Electricity Transmission (paragraph 4.7 and 8.2)
[266] RIIO-3 Sector Specific Methodology Decision – ET Annex (paragraph 1.21)

Despite this uncertainty we have developed our 'best view', which although developed prior to the NESO and CP2030 targets, plans to meet all technology target types in RIIO-T3. Figure 10-1 below was created as part of a suite of communication with stakeholders [267]to update them on how our RIIO-T3 plan is meeting CP2030. This involved the animated graph below, a blog, social media updated and a 'Bitesize Learner video' (an innovative approach from SPT to aid stakeholder understanding and awareness of our plan). This is sector leading with no other company being as responsive and adaptive to CP2030 policy.

Figure 10-1 Animated CP2030 Graph – SPT's RIIO-T3 Best view vs CP2030 (based on NESO's Jan 2025 caps)



TOs during RIIO-T2 have not stood still nor 'waited' to put projects in their RIIO-T3 baseline, we have been agile and have utilised the RIIO-T2 re-opener mechanisms and these have brought forward in excess of 100 projects through the volume driver, 4 ASTI projects in flight, 1 provisional ASTI projects in flight, 12 MSIP projects in flight and 8 tCSNP2 projects in flight.

In this context, it was not possible, prudent or in consumers' interests for TOs to commit to the majority of their load investment programmes within the baseline. This is not a failure of planning, but a reflection of a rapidly evolving policy environment in which long-term system needs are still being clarified. TOs utilising agile mechanisms in RIIO-T2 should be considered as ambitious in developing and planning the load related business plan for RIIO-T3 alongside our agile Best View to which aligns with CP2030. It is no coincidence that our best view aligns with CP2030 but demonstratable evidence of the key role we play in the NESO's CP2030 advice and analysis to government for our regional area.

<u>Contradiction in Ofgem's Position on Forecasting and Uncertainty Mechanisms</u>
There is a clear contradiction between Ofgem's decision to penalise us and its own prior statements in the SSMD. Ofgem has explicitly stated that forecasting future network need would be challenging in this price control period given the "significant uncertainty as to the pathway to net zero"[268]. It also acknowledged that a substantial proportion of TO expenditure would fall outside the RIIO-T3 baseline and instead be funded through uncertainty mechanisms[269]. At the same time, Ofgem raised its expectations on design and cost maturity for projects to be funded through baseline.
To penalise us for not including projects that were not mature enough to meet these raised expectations—at a time when Ofgem anticipated this exact scenario—undermines the consistency and credibility of the regulatory approach. As noted above, we have not stood still nor waited for RIIO-T3, we have been agile in utilising RIIO-T2 re-opener mechanisms and have played a key role in forecasting for CP2030 in the NESO's advice to government.

<u>Our Projects Are Progressing via Approved Mechanisms</u>

[267] https://www.spenergynetworks.co.uk/pages/clean_power_2030.aspx
[268] RIIO-3 Sector Specific Methodology Decision – Overview Document (paragraph 5.3)
[269] RIIO-3 Sector Specific Methodology Decision – Overview Document (paragraph 8.2)

Our decision to include fewer projects in the RIIO-T3 baseline must also be understood in the context of the wider regulatory architecture. A significant proportion of our forecast load-related expenditure is expected to be delivered through mechanisms outside of the RIIO-T3 arrangements, including:

- 4 ASTI and one provisional ASTI
- 8 tCSNP2 projects
- 12 MSIP
- More than 100 connections projects (Volume Driver)

These regulatory routes are specifically designed to fund major strategic investments in a way that allows flexibility and responsiveness to wider system needs. As such, the lower number of baseline projects submitted by us reflects not a lack of preparedness, but the appropriate routing of investment through the frameworks Ofgem itself has established for this purpose.

Generation and Demand Connections Proceed via The Volume Driver

Ofgem has continued the volume driver mechanism in light of its success in facilitating the development and delivery of projects in RIIO-T2. This mechanism is designed to allow TOs to manage the volatility evident in recent years and is critical to provide automatic, cost-reflective allowances for RIIO-T3. The timing of the NESO's Gate 2 to While Queue (G2TWQ) exercise (due later in 2025) relative to the December 2024 RIIO-T3 business plan submission date demonstrates why assigning connections projects to the baseline – with no clear means of adjusting funding to match the output of G2TWQ – would not have been in consumers' interests and that our approach in no way constitutes a failure.

Responsible Use of the Load Re-opener Mechanism

Where projects were not suitable for ASTI, LOTI or MSIP but had not yet reached baseline maturity, we have proposed to make proper and transparent use of the new RIIO-ET3 Load Re-opener mechanism. Our EJPs submitted in support of these projects clearly outline full optioneering assessments and identify preferred design options based on need, deliverability, and value. These projects were excluded from baseline not to transfer risk to consumers, but because their development timeline did not align with the business plan submission window. Ofgem has assessed and approved these EJPs, confirming the robustness of the process and the validity of the project proposals. We expect that Ofgem will confirm their approval for the need for these projects at FD so that they move to the cost assessment stage.

No Basis for Consumer Detriment Claim

The Load Re-opener mechanism exists precisely to allow such projects to proceed once they meet the necessary thresholds of design and cost maturity. This is not an ad hoc solution; it is a deliberate and central part of the RIIO-ET3 framework. It is inconsistent to claim consumer detriment from our responsible use of a process explicitly designed to avoid premature investment and reduce risk to consumers.

Moreover, we have made every effort to identify and include low/no-regret investments in the baseline, as encouraged by Ofgem. Where possible, we did so. Where uncertainty made baseline inclusion inappropriate, we used the tools Ofgem created for this exact scenario.

Summary

Penalising us in the circumstances we have described above is wrong and sends a counterproductive signal. It disincentivises responsible investment planning, undermines trust in regulatory re-opener mechanisms, and contradicts Ofgem's own guidance and strategic direction. We have acted in alignment with the letter and spirit of the RIIO-ET3 framework—using the appropriate regulatory tools, producing high-quality, regulator-approved investment cases, and remaining responsive to national policy developments.

We urge Ofgem to reconsider the penalty and instead recognise the challenges and responsibilities of investing in an uncertain, fast-evolving system landscape—something we have approached with diligence, transparency, and consumer value at the forefront. By focusing on CP2030 post business plan submission we expect Ofgem to recognise this as ambition within the BPI assessment.

Business Carbon Footprint (BCF) reduction ambition of Net Zero by 2035

We welcome Ofgem's recognition of our commitment to reduce our Business Carbon Footprint to Net Zero by 2035. While we note that Ofgem has limited its praise due to the absence of an implementation plan, this reflected our understanding of the Business Plan Guidance and our experience in RIIO-ED2, where a similar commitment did not require such a plan. We have now submitted a full, Planet Mark-accredited Net Zero Transition Plan in Annex 7.1, setting out a clear and credible route to delivering our Net Zero ambition. We hope that, upon review, the implementation plan will provide Ofgem with the necessary confidence in the deliverability of this commitment and support, alongside the points above, a reassessment of the score awarded to us under this outcome.

Stepped TIM proposal

Ofgem's assessment of Business Plan Commitments under this outcome does not recognise our efforts to advance regulatory arrangements through our stepped Totex Incentive Mechanism (TIM) proposal. The stepped TIM was deliberately designed as a bold, progressive and innovative approach to strengthen the regulatory framework to deliver infrastructure efficiently and at the lowest cost to consumers, supporting the transition to Net Zero. By introducing graduated sharing factors – 75% between ±5% of Totex, 85% between ±5–10%, and 100% beyond ±10% – the mechanism provides powerful efficiency incentives while protecting consumers from exposure to material cost deviations.

We are pleased to see Ofgem adopt a version of the stepped TIM in the DD – a clear signal that the approach is well-received and effective – yet fails to recognise or reward us for bringing this innovation forward in our business plan. This overlooks the fact that we have taken the lead in advancing regulatory arrangements that directly enable the delivery of infrastructure fit for a low-cost transition to Net Zero. We urge Ofgem to correct this inconsistency by appropriately recognising our role in pioneering regulatory developments that deliver tangible benefits for consumers and the wider energy system.

Outcome: High quality of service from regulated firms

Workforce and Diversity Commitments and Website Accessibility Commitment

We disagree with Ofgem's assessment that SPT's commitments under "High quality of service from regulated firms" are "standard" or lacking ambition. The evidence set out in our workforce, diversity and website accessibility plans demonstrates that our commitments are detailed, measurable, and extend well beyond business-as-usual expectations. Additional supporting information on our workforce and diversity commitments is provided in the Annex 6.1 to this submission, and details of our website accessibility improvements are set out in our latest Annual Vulnerability Report[270].

On workforce resilience, we are committing not only to recruitment in line with forecasted needs but to the completion of a comprehensive business transformation programme, with clear milestones and reporting obligations. This provides assurance that we will sustain capability and capacity across the RIIO-T3 period.

On skills and capability, our plan includes formal agreements with industry partners, collaboration with other TOs, and the development of a supply chain workforce proposition. These actions embed long-term resilience into the Transmission sector and cannot be characterised as "standard commitments."

On diversity and inclusion (D&I), SPT is going further than the minimum by implementing a structured training plan, improving D&I data collection across the workforce, and adopting EDGEplus – an internationally recognised certification scheme. These commitments involve measurable progress indicators, external benchmarking, and independent verification, which clearly demonstrate ambition beyond simple "well-meaning" pledges.

On website accessibility, Ofgem's assessment underplays the extent of the improvements we have already delivered and continue to build upon. We recently launched the ReciteMe accessibility toolbar, offering text-to-speech functionality, translating into over 100 languages, adjustable fonts, colours and spacing, as well as screen magnifiers and reading rulers. Beyond the introduction of the ReciteMe accessibility toolbar – which has already been used by over 1,300 customers per month, with more than

[270] 46695_SPEN_202425_AVR_submission_AW_V5.pdf

22,000 pages viewed – SPT is completely rebuilding and redesigning its website through a rigorous, consumer-focused process.

The rebuild is being undertaken in a structured way, starting with gathering business and technical requirements and translating these into user-friendly journeys that minimise customer effort (for example, pre-populated fields, “use my location” functions, and clear explanations of why certain questions are asked). We are utilising web analytics to understand existing usage patterns, running unmoderated user testing, and holding workshops with people who have lived experience of vulnerability to identify pain points and prioritise improvements.

We have a continued relationship with our third-party vulnerability partner, Three Hands, to engage with Lived Experts. Our engagement has been recognised as best practice, and Three Hands are developing a case study to showcase the high standard of vulnerable customer engagement undertaken by SPT and the positive outcomes this can deliver.

In addition, we have redesigned our design system in line with Website Content Accessibility Guidelines (WCAG 2.2) AA standards, ensuring that everything we create at a visual level is fully accessible. Our intention is to build this into comprehensive front-end development guidelines that embed accessibility by default — including compatibility with screen readers, tab-through navigation and voice command technologies — to ensure that all users can interact with our website effectively.

This is followed by an iterative re-design process, moving from low-fidelity information architecture through to high-fidelity prototypes, with copy written in plain English at a 9-year-old reading level and optimised for clarity. Before launch, sensitive journeys will also be tested with assistive technology users to confirm compatibility and ReciteMe will be validated across the site.

This comprehensive process demonstrates that our commitment is not a basic expectation but a robust, measurable and ambitious programme of digital accessibility reform. It places consumer needs and accessibility at the centre of our design process and positions SPT as proactive in ensuring its digital presence is fit for purpose, resilient and accessible to all.

For these reasons, we urge Ofgem to reconsider its assessment and to recognise that SPT’s commitments in workforce, diversity, and accessibility are detailed, ambitious, and represent meaningful steps to raise standards across the sector.

Tax Transparency Commitment

On tax transparency, Ofgem’s assessment that this commitment is also “well-meaning but a basic expectation” does not recognise the leadership position that we, as part of the Iberdrola Group, have taken on this issue. The growth of tax havens and unethical corporate tax conduct has become a prominent global concern, with aggressive avoidance distorting national economies and undermining fair competition. Close to 40% of multinational profits (around $950bn) are artificially shifted to tax havens each year, leading to a $240bn reduction in corporate income tax revenue, or 10% of global corporate tax receipts[271].

Against this backdrop, the Iberdrola Group has long recognised that tax contributions are a fundamental part of the positive social and economic impact made by responsible businesses — enabling valuable public services and supporting the infrastructure on which society and business depend.

Our tax strategy, as set by the Iberdrola Group, is founded on three fundamental pillars: compliance with tax obligations, ongoing cooperation with tax authorities, and transparency. Iberdrola is part of a small number of progressive global businesses that not only follow this approach but also “say what they pay with pride.” This is recognised through the Group holding the Fair Tax Mark — the world’s first certification for responsible tax conduct and now widely regarded as the gold standard worldwide. Importantly, Iberdrola and SSE are the only electricity network companies in the UK to hold Fair Tax accreditation, highlighting our leadership within the sector.

[271] As quoted in the Fair Tax Global Multinational Business Standard guidance notes with reference to *Thomas Tørsløv, Ludvig Wier and Gabriel Zucman (2021). “The Missing Profits of Nations.” Amounts are in current US$ and relate to 2018. Available online at https://missingprofits.world/*

The Fair Tax Mark requires businesses to demonstrate that they:

- pay the right amount of tax (but no more) in the right place at the right time, in line with both the letter and the spirit of the law;
- provide sufficient public information to enable stakeholders to form a rounded and informed view of their tax conduct and financial presence; and
- say what they pay with pride.

Our tax transparency commitments are therefore not "basic expectations," but part of a rigorous, externally accredited framework that places us at the forefront of responsible tax practice internationally. We believe this sets a high bar for corporate accountability and should be recognised as an ambitious and progressive commitment, not as a minimal compliance activity.

Sector Leadership in Consumer and Economic Impact Assessment

A further area that reflects a high quality of service from us, but which Ofgem has not recognised in its assessment, is our sector-leading work to measure the consumer and economic impact of network investment. We have exceeded minimum guidelines from RIIO-T2's consumer willingness-to-pay approach[272] by establishing a multi-year academic partnership with the Centre for Energy Policy (CEP) at the University of Strathclyde. This work assesses the long-term economic value of network investment — including impacts on GDP, jobs, and household incomes — and has demonstrated the wider benefits of early, planned investment. No other TO has replicated this initiative.

We have also ensured the findings are widely communicated to industry, policymakers, and the public. In addition to our own accessible outputs — bite-sized videos, blogs, and a joint podcast with CEP — the research has been presented in high-profile forums: at the Scottish Renewables Grid & Networks Conference (Feb 2025); at a British Institute of Energy Economics webinar (June 2025) alongside the Confederation of British Industry; as a keynote at the Westminster Energy, Environment & Transport Forum (June 2025); and in ongoing discussions with NESO, DESNZ and HM Treasury. CEP is also preparing to present this work to the Scottish Parliament Information Centre (SPICe) and has begun sharing insights within major academic networks, including the UK Energy Research Centre (UKERC) and the Energy Demand Research Centre (EDRC).

This body of work not only demonstrates leadership in consumer and economic impact assessment but also showcases our commitment to open knowledge sharing, policy engagement, and supporting CP2030 as well as the UK academic and research community.

SO:TO ODI-F

We disagree with Ofgem's characterisation of our SO:TO ODI-F commitments as "good" but lacking detail to demonstrate innovation beyond business-as-usual. We have established a clear and structured approach to delivering solutions under the SO:TO Optimisation incentive, which represents a material step forward compared to current practice.

At the heart of this approach is our Transmission Constraint Optimisation Group (TCOG). This cross-business forum – which aims to meet monthly - brings together representatives from Network Planning & Regulation, SP Transmission, Processes & Technology, Business Transformation, and Customer Service to systematically identify, develop and approve optimisation opportunities for planned outages. This process, developed during RIIO-T2, will be fully embedded and scaled during RIIO-T3 to ensure that each outage is evaluated for feasible SO:TO Optimisation solutions. Where sufficient notice exists, the TCOG enables the development of physical network solutions; where time horizons are shorter, alternative operational mitigations are assessed.

We also engage proactively and extensively with external stakeholders. We work closely with the NESO's Constraint Management team to focus on boundaries with the highest consumer costs, and we collaborate through the Joint Planning Committee with other SO:TO Code parties to identify long- and medium-term solutions in areas of significant constraint. This ensures that consumer value is maximised not only through operational optimisation but also through forward planning.

[272] There was no minimums guidance as part of RIIO-T3 in relation to consumer bill impact

In addition, we have developed processes to address short-term outages or unforeseen outage interactions that fall outside year-ahead planning. Our operational outage planning team considers measures such as deploying additional standby crews or applying dynamic line ratings to reduce constraint costs at short notice. By applying this dual-track process — longer-term planning through TCOG and NESO engagement, alongside short-term operational interventions — we ensure that optimisation opportunities are maximised across the full spectrum of outage scenarios.

SPT is also committed to the System Access Reform Programme, which is focussed on outage planning for CP2030 and beyond. Our Head of Control Room and Head of Transmission Network dedicate time from their senior leadership engineering roles to engage with DESNZ, Ofgem, NESO and other TOs in London on a regular basis, contributing to policy development and ensuring that consumer and system benefits are realised through long-term access planning.

This is not business-as-usual. It is a detailed, consumer-focused and innovative framework that formalises collaboration, embeds new processes for optimisation, and ensures that every outage is considered for solutions that reduce costs for consumers. We therefore urge Ofgem to recognise that our SO:TO ODI-F approach is ambitious, builds on experience from RIIO-T2 and represents a significant strengthening of the existing framework.

Summary

We strongly disagree with Ofgem's assessment that our commitments on workforce, diversity, website accessibility, and the SO:TO ODI-F are "standard" or lacking ambition. Our workforce and diversity plans (set out in detail in the annex) include measurable commitments on recruitment, transformation, industry partnerships, supply chain capability, and adoption of EDGEplus certification. On website accessibility, we have already delivered the ReciteMe toolbar, used by over 1,300 customers each month, and are undertaking a rigorous, consumer-focused rebuild of our website with extensive testing and engagement to ensure accessibility well beyond basic expectations. On the SO:TO ODI-F, we have established the Transmission Constraint Optimisation Group (TCOG), strengthened collaboration with NESO and SO:TO Code parties, and developed both long-term and short-term optimisation processes, embedding innovative governance and operational solutions that go far beyond business-as-usual.

In light of these ambitious, consumer-focussed commitments, we urge Ofgem to reconsider the proposed score of 0bps for the outcome 'High quality of service from regulated firms' and instead apply a reward to reflect the step change we are delivering.

Chapter 11 - Stakeholder Engagement

11.1 Overview

11.1.1 We believe Independent Stakeholder Groups perform an important role and are very supportive of these continuing on an enduring basis. Following the RIIO-2 price controls, we voluntarily retained and continued to operate an ISG. We feel the remit of the groups for the RIIO-T3 business planning period was well articulated in guidance. Whether mandated or not, we are committed to continuing to facilitate an ISG throughout the RIIO-3 period therefore we ask Ofgem for FD to recognise the enduring role of the ISG.

11.1.2 SPEN welcome and support stakeholder engagement recognising it as an important part of our role as a TO and a key part within our project planning. We ask Ofgem for clarity on how the challenges previously highlighted in workgroups will be addressed in the survey and reputational ODI.

STAKEHOLDER ENGAGEMENT QUESTIONS

OVQ 1 We would welcome any views on the enduring role of the ISGs during RIIO-3 and for future price controls.

As noted above the ISGs performs an important role and are very supportive of these continuing on an enduring basis. We note Ofgem published letter on 5 August, which recognises the importance of engaging with communities and stakeholders for CP2030[273]. During RIIO-T3 business planning we felt the remit of the groups was well articulated in guidance and the group were given a good opportunity to advise, guide, challenge and scrutinise the development of our business plan, our engagement with stakeholders and the delivery of our outputs and commitments. The input from the group undoubtedly led to the submission of a stronger business plan, to the benefit of customers and stakeholders. In future it would be preferable to receive guidance on the remit and operation of these groups further in advance of business plan submission, to allow the appropriate time for consideration, however we were fortunate that our group was already operational and able to adapt quickly to the guidance on publication. In addition, it would be useful for Ofgem to set clearer parameters around the response ISGs should submit to the Call for Evidence, to ensure a consistency of approach across groups. We are committed to continuing to facilitate an ISG throughout the RIIO-3 period therefore we ask Ofgem for FD to recognise the enduring role of the ISG.

ETQ 24 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?

SPEN welcome and support stakeholder engagement recognising it as an important part of our role as a TO and a key part within our project planning. We actively engage with the communities we serve given the significant role they play in our operation and business commitments.

We encourage review of our performance, see the significance of measuring performance and acknowledge the strengths within the newly proposed Infrastructure Stakeholder Engagement Survey. The proposal would give a uniformity amongst TOs by providing a joint methodology to follow when reviewing engagement performance. The survey would provide data and feedback that could be used to inform decisions on projects, allowing us to update community liaison policy, enhance our communications and revise future project planning approaches. A new survey would retain stakeholder engagement as a top priority within our business and allow us to measure the impact of our works on our communities and track stakeholder perception.

We ask Ofgem for clarity on how the challenges previously highlighted in the Quality of Service workgroup274 will be addressed in the survey and reputational ODI. We urge Ofgem to consider:

[273] https://www.ofgem.gov.uk/transparency-document/public-consultation-and-engagement-infrastructure-build-letter-neso-and-transmission-owners?utm_medium=email&utm_source=dotMailer&utm_campaign=Daily-Alert_05-08-2025&utm_content=Public+consultation+and+engagement+in+infrastructure+build%3a+a+letter+to+NESO+and+transmission+owners&dm_i=1QCB,901F5,2XOYPF,11L6CB,1

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- The challenge to secure balanced stakeholder responses, especially to ensure vulnerable customer inclusion, whilst engaging those who view TO activities positively and those who perceive they are adversely or disproportionately affected.

- The identification of stakeholders and give further direction on who should be surveyed: Stakeholders who responded to consultations? Stakeholders who we have leafletted? A survey is particularly challenging given the lack of stakeholder details and direct contact data held by TOs.

- The inclusion of connection customers within the stakeholder survey given our position that the QoC should be retained for RIIO-T3 and the multiple points of survey within the QoC (Please see annex 8.1 for QoC additional information).
- the overall number / sample of responses which will be deemed acceptable for a league table purposes across the TOs.
- how surveys are conducted – online, telephone, focus groups?
- the timeframe for survey to ensure a consistent approach across TOs.

SPEN would highlight the increased engagement required during RIIO-T3 given the large number of projects which require consultation, the introduction of community benefits, which requires early stakeholder engagement and raises concerns regarding stakeholder fatigue and survey sample sizes when considering a further survey. Alongside this consideration, there is further balance required in the review of survey results to try and avoid those surveyors who will always say “1” due to dissatisfaction of a project outcome regardless of the TO engagement approach in adversely affecting a league table. Whilst SPEN recognise the intention of a league table and welcome transparency between TOs, the small number of TOs and the variety in scale of different projects numbers, variation in project locations (rural / heavily populated) and thus stakeholders question the usefulness of such. We would propose the potential annual reporting is sufficient for stakeholders to review engagement performance without publication of a league table.

In reviewing the proposed for survey scope we support the identified areas of:
- promptness;
- frequency;
- methods;
- quality; and
- responsiveness to feedback.

The satisfaction scale and the ability for stakeholders to provide qualitative feedback are also welcome, however we would highlight concern and request Ofgem review the proposed survey questions.

In the proposed survey questions attached in the ET annex, appendix 1, we have the following comments and would highlight our support for the inclusion of TO ISGs to enhance the format and reach of the survey:
We would ask Ofgem to add a follow-up question at each stage of the survey to gather more detailed feedback from stakeholders, this would enable customers to elaborate in their own words, providing TOs with valuable qualitative feedback to inform potential improvements.

For example, Question 2b, if a stakeholder responder answers a question about timing with “too early” or “early,” a follow-up should be included such as, “Can you tell us more about why you felt the timing was [customer’s answer]?” Question 5 b: When considering the quality of information provided by SPT: “How could NGET/SHET/SPT improve the quality of information about current and upcoming new transmission infrastructure project?” we would encourage Ofgem to add a further point regarding the clarity of information provided by NGET/SHET/SPT on a projects next steps and processes.
Question 6: If assessing Stakeholder responsiveness to feedback, we would support the inclusion of additional questions on TO responses to help balance the survey. “If you raised a comment to NGET/SHET/SPT did they respond in a timely manner?” to include: Did the response answer the questions you raised? Did the response satisfy or resolve the issue/s raised?
SPEN would welcome further engagement with Ofgem on the proposed survey questions, potential implementation and the report template.

Chapter 12 - Innovation

12.1 Summary remarks

12.1.1 In this chapter, we respond specifically to various questions posed in the Draft Determination (DD) Consultation. Ofgem will see that our responses in this chapter reflect the absence of any significant concerns with the draft T3 NIA funding levels and proposed T3 enhancements, or with the justification provided. We recognise the positive outcomes that the proposed reforms seek to achieve, and we welcome those.

12.1.2 We recognise and appreciate the transparency and consistency with which the draft levels of NIA and SIF funding have been determined for T3. We agree with the findings of the DD that the Innovation Annex of our T3 submission would have benefited from having contained more information in certain areas. In response, we have provided below (see STPQ 9) additional information in those areas, which we trust addresses Ofgem's concerns and warrants the full measure of our original NIA funding request being allowed in the final determination.

INNOVATION QUESTIONS

OVQ 14 Do you agree with out proposed amendments to the CAM for RIIO-3?
We broadly welcome the proposed drafting and amendments to the CAM including removal of an annual submission window and continued requirement for agreement of the licensee and the Partner Licensee. Further to the initial licence consultation, we would recommend the additional amendments and clarifications:

- We propose that agreement should be reached between the ISOP, the licensee and the Partner Licensee ahead of ISOP recommendation to the Authority. This will enable any technical justifications and agreement to be reached, ensuring that the proposed redistribution of deliverables and allowance provides value to the consumer and meets the requirements of the original outputs. This also enables any cross portfolio impacts to be discussed and understood where the outputs of the project may have a direct or indirect impact on other deliverables. This amendment should ensure that recommendations by the ISOP to the Authority are suitably justified and deliverable.
- Full details of the updated mechanistic approach, including how the mechanism accounts for any variabilities pre/post decision (for example: Changes to costs from the proposal, changes to queue positions; programme delays; Impact on other outputs).
- The proposed ISOP (NESO's) approach in assessing solutions including the decision-making criteria and measuring consumer benefit.
- We recommend that the financial mechanism for calculating and determining the CAM allocation ensures that all associated costs are captured for the respective parties and can be accounted for.

We would also request that any proposed changes to the drafting / mechanism are submitted to the licensees to review ahead of finalisation of the licence drafting

OVQ 20 Do you agree with our proposed NIA funding levels?
We feel that the rationale employed for quantifying the proposed NIA funding levels is consistent with the guidance previously provided in the RIIO-3 BPG document as we have elaborated in more detail below however, we recommend that the NIA funding allowance for us be recalculated in light of the additional detail that we have provided in our response to SPTQ 9.

OVQ 22 Do you agree that £2.5m of additional NIA should be used to provide enhanced advisory services for innovators at the early stages of innovation development?
We perceive that this mechanism could help to facilitate increased participation for SME's, which would be a welcome outcome. We therefore agree in principle subject to key uncertainties, including how these

funds would be allocated and used, being more carefully considered and agreed. We would expect these funds to be awarded through a fair and transparent competitive process, and that the opportunity for regular reviews of this mechanism would be available to ensure that the funds are being spent appropriately.

OVQ 23 Do you agree with our approach to improving oversight and reporting of the NIA?
Yes, provided that the associated administrative burden is carefully minimised to avoid any unnecessary impediment to the NIA process (the agility of which we're keen to preserve) or to the ability of network operators to deliver NIA projects (the turnover of which we plan to increase in RIIO-3), we welcome this measure as an appropriate response to the concerns identified in clauses 10.20 to 10.23 of the RIIO-3 DD Overview Document. In pursuit of administrative efficiencies, we suggest considering the potential for streamlining the project registration process by removing any unnecessary duplication of field entries.

OVQ 24 Do you agree with our proposals to allocate £500m for SIF funding?
We regard the decision to base this on the current rate of RIIO-2 SIF funding (after accounting for inflation) to be justified. However, we do note with some concern that this allocation would effectively be reduced if it were to be used to fund the proposed £50m deployment fund and so, in order to maintain a like for like continuation of the SIF funding allocation from RIIO-2, we recommend a commensurate increase to the SIF funding allocation.

OVQ 25 Do you agree with our proposals to introduce a 'Programmatic Approach' to the SIF?
We welcome the intention of the proposed approach to provide greater assurance that strategic challenges are met. However, we also recognise that fundamental questions remain around the design of the 'oversight and coordination function' and therefore our support for this proposal is subject to the design of these functions having been more fully considered and agreed.

The proposed approach will increase the administrative burden on the project delivery teams, which, even if accompanied by a commensurate increase to our SIF award, would require additional resources for our organisation. Our view is that any proposals requiring an increase to our internal resources ought to be carried out through a specific consultation process, with sufficient detail on network operators proposed obligations to make an informed response.

We suggest that the proposed reporting is designed to minimise the uplift in administrative burden on network operators. The introduction of this approach should be forward looking and not retrospectively applied to existing projects.

OVQ 26 Do you agree with our proposal to introduce a £50m deployment fund, utilising £50m from the total £500m SIF allocation?
We recognise that this would be particularly useful in those instances whereby deployment offers high consumer benefit but relatively little benefit to the network itself.

However, we're concerned that a pot of £50m might be a relatively modest sum to meet these types of deployment opportunities across all TO's over the 5-year period of RIIO-3.

We're also concerned that, by sourcing the deployment fund from the total SIF allocation, Ofgem will effectively reduce the total SIF allocation relative to the RIIO-2 period.
That said, we're committed to the rapid deployment of proven innovation and so, in pursuit of that goal, and in recognition of Ofgem's findings that this proposal has the potential to provide a better balance of agility and accountability than alternative deployment incentives previously considered (i.e. a re-opener or a UIOLO allowance), we're inclined to agree, in principle, with the proposal, subject to the following conditions.

We would expect these funds to be awarded through a fair and transparent competitive process and would appreciate confirmation of the opportunities we would have for regular reviews of this mechanism over the RIIO-3 period to ensure that the funds are being spent appropriately.

We note the potential for the £50m deployment fund to be increased within the RIIO-3 price control period, and would like to request confirmation that, in such a scenario, the additional funds would not come from the total £500m SIF allocation.

OVQ 27 Do you agree that the deployment fund should also be open to innovation projects that haven't been funded through NIA, NIC or SIF?
In response to OVQ 25 above, our provisional support for the 'programmatic approach' was based on the recognition that the SIF is strategic in its nature, and that it therefore warranted the proposed accountability measures to ensure delivery of those strategic outcomes. It is in this same recognition (of the strategic nature of the SIF) that we express a concern with the proposal to use the SIF allowance to fund innovation deployments that do not necessarily share the *strategic* objectives of the SIF (i.e. those that originate from sources other than SIF).
Our support for this proposal is therefore subject to criteria being in place to limit eligibility to only those innovations that are aligned with the SIF strategic goals. We would appreciate confirmation of this being the case and would like to request details of the applicant eligibility criteria please.

OVQ 28 Do you agree with our proposal to reverse the SSMD position of removing the Discovery phase from SIF?
We agreed with the original SSMD decision to remove the Discovery phase, on the basis that there was excessive bureaucracy in applications and oversight for early-stage projects and that this early-stage work could be delivered via the NIA.
However, we regard the rationale, provided in paragraph 10.41 of the Overview Document, for subsequently reversing that decision to be reasonable. Therefore, provided the proposed 'Programmatic Approach' still allows for successful NIA projects to progress directly into SIF Alpha projects, we have no objection to this proposal.

OVQ 29 Do you agree with our proposals to retain the core aspects of the SIF for RIIO-3?
Yes, we have no objection to these remaining the same.

OVQ 30 Do you agree with our proposals for a more flexible approach to contribution rates to fund SIF projects?
Whilst we agree in principle that there is a case for the contribution rate of less risky projects to increase beyond 10%, we would welcome the opportunity to work with Ofgem on what an appropriate contribution rate would be in each case (in light of the bespoke project specifics) and to agree on that figure bilaterally.

OVQ 31 Do you agree with updating the SIF eligibility criteria and assessment process?
It's unclear, from the limited information provided in Clause 10.45, precisely what the proposed updates would comprise but, subject to a more comprehensive review of the detail as it emerges, we have no specific objection at this point.

OVQ 32 Do you agree with our proposal to establish a direct pathway for transformative projects to seek Ofgem's support for funding?
We understand and appreciate the concern raised during the SSMC that "*network companies can act as gatekeepers to transformative projects that do not benefit them directly*".
We recognise that the proposal for a direct pathway to Ofgem, addresses that concern by ensuring that project proposals that do not benefit networks are reviewed and assessed by an impartial body.

We welcome the explicit clause in the Overview Document confirming the absence of any obligation on networks to take forward any of the proposed projects.

We're concerned that the implied increase in engagement activity will inevitably engender additional administrative burden for network operators which, even if accompanied by a commensurate increase to our allowance, would impose further resource constraints to our organisations. Our view is that any proposals requiring increase in internal resource constraint ought to be carried out through a specific consultation process, with sufficient detail for network operators to make an informed response.

We would therefore like to request additional, quantitative detail on the level of the additional engagement that networks are expected to provide during the RIIO-3 period as a result of this proposal.

OVQ 33 Do you agree on the need to clarify roles and responsibilities within the innovation ecosystem, and the factors that we should consider?
We value clarity of roles and responsibilities and welcome the proposal to enhance this, provided that such clarifications do not result in any material change to the status quo.

OVQ 34 Do you agree with our approach to improving reporting of deployed SIF projects and lessons learned post-funding?
Yes, provided the extra effort that will be associated with the elaboration of said reporting can be accounted for in the SIF funding application.

SPTQ 9 Do you agree with the level of proposed NIA funding for SPT?
We agree that the Innovation Annex of our submission would have benefited from having contained more information in the four areas in which it was perceived to have been lacking.
In response to that reasonable criticism, we have provided, below, additional detail which we trust addresses Ofgem's initial concerns about the lack thereof and therefore warrants the full measure of our original NIA funding request being allowed:

1. *NIA Funding justification*

i. The DD concluded that information was lacking to explain *how* our RIIO-T3 NIA request was quantified. In the response that follows, we describe how, having identified the 22 x NIA activities that we intended to pursue in RIIO-T3, the associated costs were determined in the 'T3 NIA Activity - Cost model' calculation sheet, which was included in our original RIIO-T3 Business Plan submission, and is available again upon request.

For simplicity, the following tabs in the 'T3 NIA Activity - Cost model', were hidden in our submission and will need to be unhidden[275] in order to trace the methodology described below:

- 'Archetyping T2'
- 'Archetyping Summary'

Step 1: Archetypal T2 NIA activity 'categories', with costs:

a) ('Archetyping T2' tab): A list was compiled of RIIO-T2 NIA projects their associated project costs. The list included 131 projects registered by all GB Electricity Transmission companies.
b) ('Archetyping T2' tab, columns H-J): For each of the projects listed, its constituent 'categories' of innovation activity were distilled e.g. 'Predictive maintenance'; '*Reducing Network losses'; 'Alternatives to SF6'*. (Up to three activity categories were identified per project, however, Category 1 was the leading category for each specific project).
c) (Archetyping Summary' tab, column E): RIIO-T2 archetypal activity 'category' costs were determined by averaging the cost of each leading category across the list of compiled projects. This resulted in estimating the cost of 32 different activity 'categories'.

Step 2: RIIO-T3 NIA costs: by 'Activity'

a) ('T3 NIA Cost Model' tab, columns AI-AK): Each of the 22 proposed RIIO-T3 NIA activities were expressed in terms of the archetypal T2 innovation activity 'categories' that they respectively seek to progress (up to a maximum of 3 categories per activity).
b) (Column AL): The 'initial' cost estimate of each proposed RIIO-T3 activity was then determined by summing the T2 archetypal 'category' cost [Step 1.c], for each 'category' associated with that given RIIO-T3 NIA activity.
c) (Column AR): This 'initial' cost estimate was subsequently refined (always resulting in a net reduction), by applying weighted factors (to discount the 10% compulsory contribution elements of the costs and any project costs that were not associated with the categories being considered, and account for inflation over the period), resulting in a 'final' cost estimate for each of the 22 x RIIO-T3 Innovation Activities.

Step 3: RIIO-T3 NIA costs: by Area of Focus (AoF)

a) (Columns AD-AG): Each of the 22 x proposed RIIO-T3 NIA activities were grouped one of the 4 x Areas of Focus (AoF).

[275] To unhide them, open the 'T3 NIA Activity - Cost model' in Excel; right-click on any tab at the bottom of the screen; select the 'unhide' option; select the tabs you wish to unhide; click OK.

b) (AD25-AG25): The RIIO-T3 NIA cost per AoF was calculated by summing the final costs of those RIIO-T3 activities associated with that AoF.

Step 4: RIIO-T3 NIA costs: total

a) (AR25): The total RIIO-T3 NIA request was calculated by summing the final cost estimates for each of the proposed 22 x RIIO-T3 Activities.

ii. The DD also determined that that information was lacking to explain what other *options* were considered. Here, in response, we describe the alternative costing options that we considered and why we chose the method we did.

Option 1: Cost by project.
We considered the option of costing each proposed RIIO-T3 NIA activity, from the ground-up as it were, by contriving a plausible estimate of the number and scope of NIA projects that we might successfully conceive under each activity during RIIO-T3, and then estimating the labour and materials costs associated with their delivery.
This costing rationale was quickly dismissed, however, due to the lack of reliable insight we have at this stage to allow us to responsibly estimate the scope and number of NIA projects that we anticipate delivering during RIIO-T3. Our Innovation Annex makes no attempt to forecast these unknowns; rather, our plan is limited to detailing the 'Activities' that we intend our RIIO-T3 NIA projects to address. The projects themselves, and their detailed scope and number are still to be developed by running further engagement with internal and external stakeholders during the RIIO-T3 regulatory period.

Option 2: Cost by activity
Considering the limitations of Option 1, we explored an alternative approach whereby we could estimate our RIIO-T3 NIA costs by proxy; through application of archetypal categories of innovation 'activity', and the historical T2 costs associated with their pursuit. This approach employed far fewer assumptions than option 1 and was recognised therefore as the more scientifically robust of the two. Its implementation is described in detail, above, in part 'i' of this response.

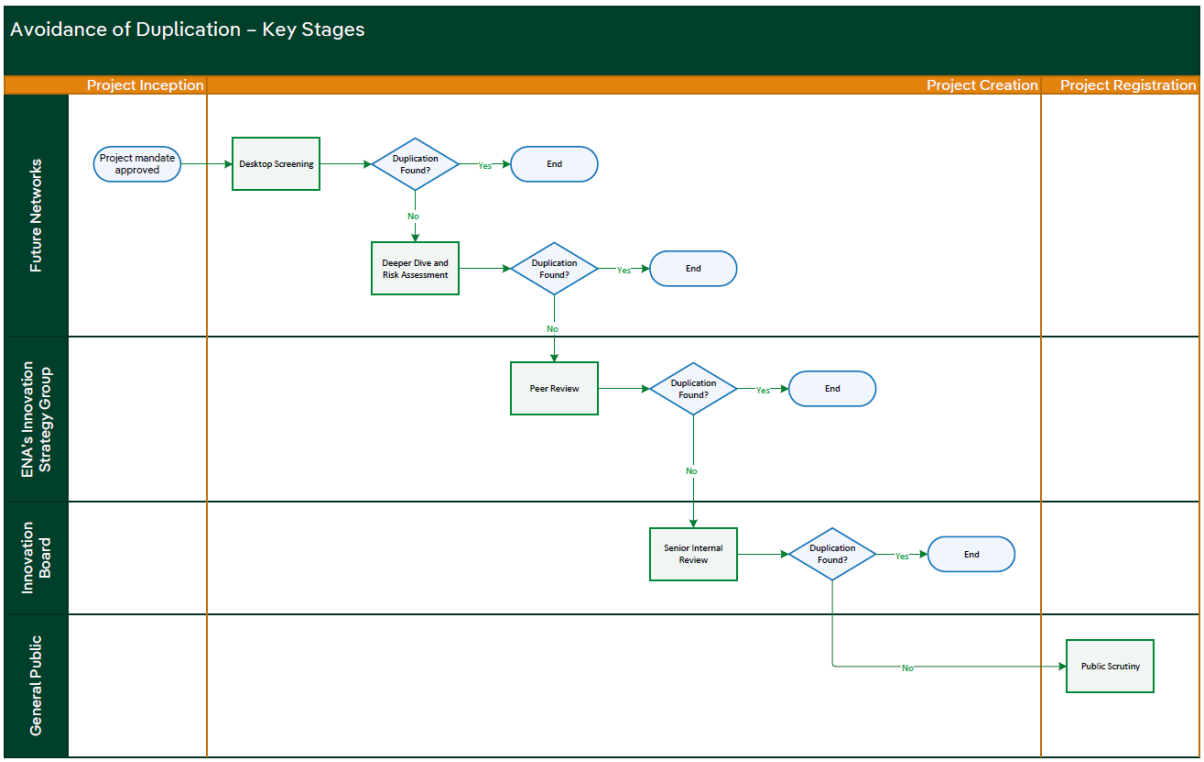
2. <u>Duplication</u>

The DD noted that detail was lacking with regards to the SPEN *processes* in place to ensure projects are not duplicative, and how these processes are applied. This detail is provided immediately below.

i. Process

The process we employ for creating NIA Projects is best illustrated in the figure below:

Figure 12-1 - Timeline Diagram of NIA Projects



ii. Application

The first stage to our avoidance of duplication is our commitment to collaboration at the ideation stage of innovation, through active participation in the following groups, events and commitments:

- The Innovation Strategy Group (ISG)
- The Energy Innovation Centre (EIC)
- The annual ENA Basecamp event
- Our commitment* to the coordinated collaboration strategy that we agreed with other Transmission Networks (*See Fig 14 in our Innovation Annex)

This commitment to collaborative ideation creates an environment for the cultivation of stakeholder-driven innovation proposals that are cognizant of the innovation landscape, and thereby helps to engineer out potential for duplication by limiting the ideation to focus exclusively on the most original and pertinent of solutions.
Once an idea has been conceived then, to manage the risk of duplication, the following steps are taken on its journey to becoming a project:

a) Desktop Screening
   - Prior to developing any conceptual innovation projects, we consult the ENA Smarter Networks Portal, amongst other online sources, to identify and research the existence of any projects that might exhibit any potential for duplication

b) Deeper Dive & Risk Assessment
   - Any instances of potential synergy or duplication are then followed-up with meetings, that we organise with the lead network operator of those projects, to examine in detail those elements which exhibited the closest synergies and/or risk of duplication.

c) Peer Review
   - Once the above screening process is complete and concludes, to our satisfaction, that the risk of duplication from the proposed innovation is sufficiently low to proceed, the concept is presented to the Innovation Strategy Group (ISG) and they're invited to scrutinise our evaluation of that risk.

- This forum, also known as the Energy Innovation Managers (EIM) group, comprises innovation managers from various UK electricity transmission and distribution operators, and it meets monthly to review and cross examine innovation proposals.

d) Senior Internal Review
- Provided the ISG flags no concerns about the potential for duplication, the concept is elaborated into a more detailed project proposal, which is then subjected to intense scrutiny by the following internal bodies:
- Innovation Board (IB)
  - This group, which meets monthly, comprises senior stakeholders from across the business.
  - They review and assess each innovation proposal to ensure it aligns with our strategic goals and avoids duplication.
- System Review Groups (SRG)
  - There are 3 x SRG's within the business, respectively focussed on 'transmission', 'distribution' and 'data & digitalisation'.
  - These groups meet periodically to assess the risk of innovation project proposals conflicting with the group's existing or proposed systems or leading to any unnecessary duplication of their related activities.

e) Public Scrutiny
- Once a project proposal has successfully navigated the screening and review stages described above, it is registered on the ENA Open Networks Portal, where it is available to public scrutiny with regards to its freedom from duplication and value for money.

3. Dissemination

The DD reported that our business plan was lacking detail of our historical and future planned dissemination activity. We elaborate on each of these below.
Throughout the course of any innovation project, we provide at least yearly updates to both internal teams and external stakeholders. This keeps everyone informed about progress, challenges, and emerging insights.

Internal

We maintain team briefings and have established an informal network of departmental focal points to ensure that innovation insights are shared throughout our company. Focal points include:

- Whole System
- Data & Digitalisation
- Network Resilience
- Power Electronics

We also present innovation learnings at internal events including those listed below:

- SP Innovation Forum
- District Engagement Roadshows
- SPEN Processes & Technology Away Day

External

We produce project closedown reports which capture critical learnings, outcomes, and recommendations for future work or potential adoption into business-as-usual practices. This ensures that the value of each project – including lessons learned - extends beyond its immediate scope, informing future initiatives and operational improvements.

We upload project reports and key learnings to the ENA Smarter Networks Portal, making them accessible to a broad public audience and we regularly promote the publication of new reports and upcoming dissemination events via our social media presence.

We also upload project reports directly to our SP Energy Networks Innovation web page, which we have recently refreshed to make information more accessible to potential partners and stakeholders; retiring outdated content and modernising the navigation to more easily sign post our innovation strategy, projects and key documents. Stakeholders can now sign up for our innovation stakeholder list that enables them to register their interest in our events and comms.

We participate in industry events and forums to share our project learnings and engage in valuable knowledge exchange with our peers.
Examples of such events and forums include the following:

- Project Specific workshops and dissemination events;
- Utility Week Live;
- Energy Innovation Summit (EIS);
- Conseil International des Grands Réseaux Électriques (CIGRE)
- Institution of Engineering and Technology (IET)

An illustration of some of our more recent historical dissemination activities is presented below:

- Project BLADE
    - Show and Tell for Alpha (23/04/24) – the event is recorded on youtube and the presentation was on the outcomes of the alpha project as part of the SIF obligations. Carbon Trust presented it.
    - EIS Presentation on developing operational resilience (29/10/24) – presentation on how BLADE contributes to ensuring operational resilience, it was part of a panel that included P4R and was followed by a panel Q/A
    - Utility week live – keeping a step ahead of service disruption session (21/05/25) – This session is about sharing best practice in minimising the likelihood of outages and pipe bursts and how to communicate to customers and gain practical insights to minimise customer dissatisfaction when responding to unforeseen disruption and planned asset management. Daniel Barlow, Future Network Technology Manager in SPEN, presented how new technology (BLADE) can enable wind farms to restore the grid following a national power outage and minimise service disruption
    - We recorded a podcast episode hosted by UKRI on network resilience alongside P4R. I am intentionally not including any detail here as the outcome was to rerecord the episode following the feedback from SPEN communications department. Happy to provide more detail if you see value in including this.
- Project Dynaload –
    - CIGRE Paris 2024 presentation (25/8/24-30/8/24) – This was presented by SINTEF, but not on behalf of SPEN, it is on behalf of the full project consortium. Here is the paper that was presented - Madshaven2024mcp_AAM.pdf

4. TOTEX funding

The DD concluded that we provided insufficient information on why each workstream cannot be funded from its Totex allowance, stating only that NIA is used to fund smaller-scale, higher-risk projects, that carry a level of risk they are not prepared to take as part of BAU funding. A more detailed justification is provided below:

We plan to harness our RIIO-T3 Totex allowance to fund innovation activities which, often through operational efficiencies, offer a *high-confidence* of *near-term* benefits to *our* business.
Examples of such proposed activities in our RIIO-T3 business plan include the following:

i. the automation of connection processes,
ii. technology-enabled inspections, and
iii. the roll out of SF6-free switchgear.

By contrast, we plan to leverage NIA and SIF funding to support innovation that is not necessarily expected to yield near-term financial returns for our business, and therefore does not make commercial sense to pursue through our Totex allowance, but which:

- supports high-risk / high-reward, system transformation, and
- enables more strategic, longer-term benefits that extend to the wider system and our consumers.

In these instances, stimulus funding allows us to pursue experimental innovation that, if it were to be funded through our Totex allowance, would pose an unacceptably high financial and operational risk to our consumers.

It is noteworthy that, in some instances, we're planning to use a *combination* of both Totex-funded innovation and NIA-funded innovation to advance distinct elements of a common technology during RIIO-T3. For illustration, we include an excerpt from our response to Supplementary Question 'SQ SPEN093 re Innovation', in which we provided a specific case study of one such instance in which, Totex-funded innovation will comprise the roll-out the low-risk, proven aspects of the technology, and NIA funding will be used to trial and de-risk the relatively higher-risk features of those same technologies, that are not yet ready to be included in our RIIO-T3 BaU roll-out programme. The table below shows the distinct scopes of the innovation activity that is being Funded through Totex and NIA for the two innovative technologies referred to in this instance:

Table 12-1 - Scopes of Innovation Activity

Scope	AI-generated connection offers	Advanced inspection & surveillance using robotics and analytics
T3 *Totex*-funded innovation	This work seeks to roll-out in the following areas: - Automation of contract creation during connection process. - Pre-planned customer engagement to provide updates on contract status	Integration in the following areas of: - Internet of Things (IoT) devices - Machine learning (ML) models - Cloud-based infrastructure
T3 *NIA*-funded innovation	The proposed NIA trial seeks to investigate the following higher-risk innovations in the following areas upon completion of Connections Reform: - How parts of the connection offer technical and commercial processes could be modified and potentially automated. - (NB: The scope of this proposed NIA activity will not be defined or delivered until after the Connections Reform process has been concluded.)	The proposed NIA trial seeks to deliver: Analysis in the areas of: - field data gathered from the devices - efficacy of the ML models Optimisation of the: - Methods for operating the deployed assets - ML models to predict maintenance requirements Proof of concept for: - Application of LiDAR technology to produce 3D models.
What is additional in the NIA that justifies stimulus funding?	- We're proposing to review internal processes associated with connection offers and their suitability for potential automation, following the conclusion of the Connections Reform.	We're proposing to trial new and untested: - Inspection Methods, and - ML models for predictive maintenance. We're also proposing to develop a proof of concept for the use of LiDAR to produce 3D models. Deploying these yet unproven methods, models and concepts in an operational, BaU environment would be premature at this stage.

In conclusion, we agree that the Innovation Annex of our submission would have benefited from having contained more information in the four areas in which it was perceived to have been lacking, and we trust that the additional detail provided in this response to SPTQ 9 satisfactorily addresses those gaps, and therefore warrants the full measure of our original NIA funding request being allowed. We therefore recommend that that Ofgem recalculate our RIIO-T3 NIA funding allowance in light of this response.

Chapter 13 - Workforce and Supply Chain

13.1 Workforce

13.1.1 We are pleased that Ofgem recognises the significant efforts we have made in developing and implementing our Workforce Resilience Strategy. It is encouraging to see the regulator acknowledge the increased costs and evolving requirements associated with operational training, which are essential to ensuring our workforce is equipped to meet current and future challenges.

13.1.2 We fully agree with Ofgem's assessment that we have met all the necessary requirements to demonstrate the Workforce Resilience objectives. We also support the regulator's approach, particularly the emphasis on future workforce resilience as a primary consideration. This alignment reinforces our shared commitment to building a sustainable, skilled, and adaptable workforce for the years ahead.

13.2 Supply Chain

13.2.1 We agree with Ofgem's views, and recognition of the supply chain challenges within the electricity transmission sector. We welcome Ofgem's decision to provide development funding via Pre-Construction Funding (PCF) and the continued use of the Advanced Procurement Mechanism (APM).

13.2.2 We would like to highlight some of the measures we have put in place in relation to supply chain resilience as detailed in our Workforce & Supply Chain Resilience Strategy Annex (i) placement of bulk orders for transformers providing competition, aggregation, and larger commitment across multiple awardees, (ii) different contracting models allowing access to tier one, two and three contractors, (iii) more balanced risk profile (terms & conditions) and (iv) reduce tendering resources/costs through the use of more frameworks.

WORKFORCE and SUPPLY CHAIN QUESTIONS

OVQ 9 Do you agree with our views on the Workforce Resilience Strategies?
We agree with the view from Ofgem that we have met all the requirements to demonstrate the Workforce Resilience objectives identified. To deliver in line with this strategy we require the right resources at the right time to deliver the step-increase associated with our future work programme and consequently deliver future workforce resilience. This reinforces the critical importance of having appropriate levels of Indirects funding to ensure the required workforce growth trajectory, and thus the need to address the flaws in the current approach which are we set out in detail in Chapter 2. We agree with the view from Ofgem that we have met all the requirements to demonstrate the Workforce Resilience objectives identified.

OVQ 10 Do you agree with our views on the Supply Chain Resilience Strategies?
We agree with Ofgem's views, and recognition of the supply chain challenges within the electricity transmission sector. We welcome Ofgem's decision to provide development funding via Pre-Construction Funding (PCF), although we have provided evidence that the 2.5% proposed by Ofgem will create a funding gap between this and the APM. Please refer to ETQ.26 for further information.

ETQ 25 Do you agree with our proposal to retain the APM for RIIO-ET3 in its current form?
We support Ofgem's proposal to retain the APM for the RIIO-ET3 period. Securing supply chain capacity ahead of regulatory certainty remains essential to achieving CP2030 and broader net zero targets. APM enables us to engage supply chain partners in a more anticipatory and innovative manner, delivering better value for GB consumers, stimulating supply chain development, and supporting economic growth through a robust and visible order book.

Supply chain constraints are widely recognised by industry and Ofgem as a key driver of project delays. The Network Commissioner's review and the Transmission Action Plan both prioritise addressing these challenges. Retaining APM is a positive step toward accelerating the development of the GB transmission network.
We broadly support APM in its current form. As a recent positive addition to the RIIO-ET2 licence, we are working closely with Ofgem to resolve practical implementation issues and to ensure the mechanism delivers on its intended purpose. Alongside clarification, we would request Ofgem review the below to consider strengthening the licence for RIIO-ET3.

- **Eligibility of services** and how these are reported within the APM. Given the wide range of supporting evidence and recognition [276] [277] [278] [279] [280] [281] [282] that labour and skills are a key factor in achieving ambitious RIIO-ET3 targets, services are only currently applicable within the APM when they can be linked and traced to an APM cost category. To ensure skills and labour do not become blockers for delivery, the scope of APM should be expanded for RIIO-T3 enabling TOs to secure sufficient resource.

- **Definition and treatment of ineligible expenditure**. The RIIO-ET2 licence and governance document are not transparent in how Ofgem will review, and potentially disallow APM spend. We met with Ofgem (24 June 2025) and raised questions to clarify and gain additional certainty on how reporting will be reviewed, how the APM replenishing pot would be replenished if an asset became stranded and highlighted the need for full transparency.

- **Combined APM use with Early Construction Funding (ECF):** APM should be permitted alongside ECF for ASTI projects. With ECF providing a broader scope and APM enabling frictionless access to advanced procurement allowances for specifically restricted cost category assets, playing a critical role in the timely and effective delivery of ASTI schemes. For the avoidance of doubt, eligibility for both ECF and APM allowances does not risk doubling funding, and would be easily managed at Project Assessment stage.

- **Regulatory Cost Assessment Clarity:** The licence should be strengthened further to clearly define Ofgem's cost assessment criteria, ensuring procurement decisions are evaluated fairly based on information available at the time, without hindsight bias. Ofgem should also clarify how ineligible expenditure and stranded asset expenditure will be treated, including the impact on the overall UIOLI allowance, and the subsequent treatment of ineligible APM costs through business-as-usual regulatory funding routes. We recognise that the informal submission (29 August '25) will form a key part in the formal RRP process and welcome the necessary engagement with Ofgem that will be required post submission.

- **GIS:** We welcomed the Ofgem decision of 20 March '25 and the governance document[283]. We continue to advocate that GIS switchgear equipment should not be a bespoke item, given the flexible supplier terms we could secure, in advance of any project assessment. Recognition of GIS as a non bespoke cost category would reduce future regulatory burden.

- **Strategic Land:** In initial APM discussions, the mechanism was considered for the purchase of strategic land. Whilst we recognise this was discounted, we continue to raise the funding gap for strategic land in RIIO-ET3 and ask that Ofgem considers closing this gap (please see our response to ETQ26). Once reviewed, as suggested above, it may be necessary to amend the

[276] Infrastructure update: Electrical power transmission | Building
[277] Labour and skills shortages in transport, energy, infrastructure and the digital sector | EESC
[278] Energy union: UK electricity grid upgrade will fail on skills shortage – EnvironmentJournal
[279] Clean technologies are driving job growth in the energy sector, but skills shortages are an increasing concern - News - IEA
[280] Skills for the Grid: the power sector needs people to drive the transition
[281] Clean power by 2030
[282] Lessons from industry leaders - IDF Round Table - Autodesk: Clean Power delivery
[283] Advanced Procurement Mechanism (APM) Governance Document

licence to formalise and clarify the mechanism to ensure it is functional and appropriate for TOs to address the challenges of RIIO-ET3.

ETQ 63 Do you agree with our approach to operational training? What else should be considered within this approach?
Yes, we agree with Ofgem's proposed approach. The primary considerations are having sufficient resource to enable the future work programme and future workforce resilience. We do not consider that anything else should form part of the approach.

Chapter 14 - Environmental Sustainability

14.1 Overview

14.1.1 Overall, we are largely supportive with the outcome of our Environmental Action Plan as reflected in the DD. In particular, we welcome the inclusion of the UIOLI allowance for carbon compensation (offsetting), which is a crucial mechanism for Transmission Owners (TOs) to meet their science-based targets. We also appreciate the baseline funding allocated for SF_6 mitigation; however we do not support the need for a SF_6 PCD and look forward to working with Ofgem to update current mechanisms to make them adequate for our needs.

14.1.2 We are encouraged by the recognition of environmental pollution prevention activities across the network, especially given the wide range of pollutants that are unavoidably involved in our operations. It is reassuring to see funding directed toward this important aspect of environmental protection. Additionally, we welcome that Ofgem has acknowledged the significance of reducing building energy use, and we welcome the associated funding as a positive step toward minimising our operational environmental impact and scope 2 emissions.

14.1.3 Ofgem's guidance rightly encourages network companies to set science-based targets and take meaningful steps to reduce their own emissions. We therefore welcome that Ofgem has recognised the ambition of our 2035 Net Zero Greenhouse Gas target. As a market leader and an electricity network company responsible for facilitating achievement of the UK's Net Zero targets, we believe it is our responsibility to lead by example, and we have included our Net Zero Transition Plan (Annex 7.1) (finalised since RIIO-T3 Business Plan submission) to demonstrate more fully how we intend to deliver this commitment in practice.

14.1.4 However, we must highlight that achieving this target will not be possible without adequate funding to address embodied carbon. Without sufficient support in this area, the full implementation of our transition plan and the broader emissions reductions it enables will be at risk.

14.1.5 We are concerned that the Draft Determination does not sufficiently acknowledge the impact on the environment of the increased investment in the transmission network to support the connection of new renewable generation and facilitate the UK's transition to net zero. Specifically, while this investment is essential, it will also result in significant environmental impacts, including increased carbon emissions and greater use of land and natural resources due to the scale and pace of construction. We believe it is vital that these environmental trade-offs are explicitly recognised and addressed within the determination process.

14.2 Low Carbon Construction Materials and Opportunities UIOLI

14.2.1 We respectfully request that Ofgem reconsider its rejection of the 'low carbon construction materials and opportunities' Use-It-Or-Lose-It (UIOLI) allowance. A UIOLI mechanism is the most appropriate approach for supporting both load and non-load projects under this initiative. Given the emerging nature of this area within the UK, an uncertainty mechanism offers TOs the necessary flexibility to progress these initiatives as and when feasible, while also supporting the supply chain in adapting to more sustainable project delivery methods.

14.2.2 Importantly, the UIOLI approach ensures that any unutilised funding is returned to consumers. As outlined further in this section, the proposed mechanism also applies the Green Book's carbon pricing requirements, reinforcing its economic and environmental justification.

14.2.3 In acknowledgement of Ofgem's position in the DD, we have explored alternative integration methods within cost assessments. However, we note that these alternatives are less straightforward complicated and burdensome for both the regulator and TOs, do not provide the flexibility required and would require additional development both before and after FD to be viable.

14.2.4 Therefore, we reiterate our view that a UIOLI mechanism remains the most efficient and effective and transparent means of facilitating this initiative whilst protecting consumers.

Baseline funding

14.2.5 In this response we have provided further justification for this UIOLI allowance, along with evidence of the customer benefits it delivers, including an updated version of our Capital Carbon Annex 7.2, which offers additional detail on the proposed funding areas.

14.2.6 In the DD, Ofgem suggests that the 0.3% allowance for low-carbon materials should be incorporated into project costs. However, when developing our business plan costings for non-load and baseline projects, these costs were not included in the initial assessments due to the expectation that they would be covered by the UIOLI allowance. In the absence of that UIOLI allowance, unless Ofgem can propose a mechanism to reintroduce these costs into baseline project submissions, we will be unable to apply them to any of the baseline projects already submitted.

14.2.7 Regarding the emerging low-carbon opportunities fund proposed within the UIOLI, Ofgem has suggested that innovation funding may be more appropriate. We consider that may be based on Ofgem's misunderstanding of the intended scope of this fund which is to provide funding to support the deployment of solutions that are new to the network but not innovative in the traditional sense and would not meet the criteria for innovation funding. For example, the use of 3D-printed concrete bases for transmission assets is not a novel concept, but it has not yet been trialled in our context. While such solutions may carry higher upfront costs, at least until their use becomes business as usual and economies of scale bring those costs down, they offer significant carbon reduction potential and would not meet the criteria for innovation funding (however where a concept is truly innovative and meets governance for innovation funding that is the funding route that we will take). This fund will allow the flexibility to deliver the most efficient carbon savings across the portfolio of projects and is designed to deliver the necessary carbon reductions in the necessary timescales whilst providing demonstrable value for money for customers. We have proposed a threshold whereby any solution must deliver carbon savings at or below the DESNZ carbon price to qualify for funding. We have also calculated the magnitude of the fund based on the delivery of carbon reductions aligned with the necessary trajectory to meet our 2035 Net Zero Greenhouse Gas target. Further detail on this proposal is included in the Annex 7.2.

14.2.8 We therefore respectfully request that Ofgem reinstates the Low Carbon Construction Materials and Opportunities UIOLI mechanism for baseline projects, specifically for the £5.65 million allocation referenced in Net Zero BPDT Table 8.12. This funding cannot be directly reintegrated into baseline project costs without an appropriate and transparent mechanism provided by Ofgem. Reinstating the UIOLI would ensure that companies are able to manage capital carbon reductions effectively while maintaining accountability and value for money.

Load Reopeners

14.2.9 In circumstances where Ofgem is not willing to accept a UIOLI approach for load projects then we propose that for, LR and CSNP-F cost submissions, the costs associated with low-carbon materials and emerging technologies can be incorporated directly into project cost submissions, as requested by Ofgem. The calibration of the RIIO-T3 Volume Driver and load use-it-or-lose it will require further engagement with Ofgem to agree a fair and reasonable treatment for costs noted above[284]. To support this, noting that these specific costs would be subject to future UIOLI review we suggest the following adjustments to the cost allowance process:

14.2.10 First, we ask that our justification for allocating 0.3% of project costs to low-carbon materials be accepted in cost assessments. Where these costs are included in project's cost submissions, we propose they be approved without further challenge, recognising their alignment with Ofgem's environmental objectives. Note, this will be subject to availability of materials, and if as the project

[284] The timing of the calibration process for the RIIO-T3 VDUM will fix unit cost rates for five years. It is not appropriate to include additional requirements such as low-carbon materials and bio-diversity net gain, whilst the market is immature without adequate protections to both companies and consumers.

matures and there is inadequate availability at a suitable cost for a particular material then the funding will not need to be used.

14.2.11 Second, for emerging low-carbon technologies, we propose that the 1.1% allocation be accepted within project cost submissions where applicable. As projects mature, if suitable solutions are identified that meet the customer value-for-money threshold defined by the DESNZ carbon price then the funding should be released and made available for use. If, however, no appropriate solution emerges for a given project, then the funding will not need to be used.

14.2.12 This approach ensures that funding is only used where it delivers measurable carbon savings and value for customers. It facilitates adoption of new low-carbon solutions as they become commercially viable and enables appropriate decisions for different projects

14.2.13 To support administrative efficiency and transparency, we propose that if Ofgem agree to award both of the two funding streams (proposed at 0.3% and 1.1% of project costs) then they be consolidated into a single funding allocation of 1.4%. This unified approach would streamline the cost assessment process, reducing complexity and duplication and will increase clarity for all stakeholders.

14.2.14 We propose development of reporting detailing the low carbon solutions implemented with their costs and carbon savings, we welcome working with Ofgem to define the format. However, we must reiterate that a UIOLI provides the most flexibility and transparency for all stakeholders.

14.3 Risk to RIIO-3 Commitments

14.3.1 If these costs are excluded from the project costing process, we will be unable to fulfil the commitments outlined in our RIIO-3 submission, which Ofgem has indicated its intention to approve:

- Deliver economically efficient actions to reduce our scope 1, 2 and 3 Greenhouse Gas (GHG) emissions in line with our Net Zero GHG target
- Implement cost-effective sustainable materials and solutions in our construction programmes
- Improve our carbon footprint reporting to cover whole life carbon associated with new projects

We do not believe this is Ofgem's intent and does not align with Ofgem's net zero duties.

14.4 Biodiversity Enhancement

14.4.1 Biodiversity Enhancement or Biodiversity Net Gain (BNG) as it is known in England is a rapidly developing policy area in the UK, with new statutory requirements being introduced during the current price control period and expected to strengthen further over time. We welcome Ofgem's recognition of the importance of funding in this area. However, we must highlight that the current limitations placed on Biodiversity Enhancement funding may result in significant residual impacts on the natural environment, particularly for projects that fall outside the scope of planning permissions for which biodiversity enhancement would not be funded under Ofgem's proposals.

14.4.2 As statutory Biodiversity Enhancement requirements are extended to all planning-related activities, the availability of land for statutory biodiversity enhancement is expected to decline, while demand increases. This will likely drive up the unit cost. It is therefore essential that the immaturity and volatility of this cost area are acknowledged within the costing process.

14.4.3 It is also important that we have access to pipeline development funding in order to be able to have offsite biodiversity enhancement schemes available to access as projects are consented, that meet the requirements of the project with respect to location, timing, habitat type and magnitude. Having pipeline funding available will also reduce the risk that a lack of appropriate schemes causes delays to planning consent timescales. This is explored further in ETQ 11 below.

14.4.4 To ensure compliance and environmental integrity, we propose that flexibility be built into the treatment of Biodiversity Enhancement-related costs within the load and non-load re-openers. Biodiversity costs are still very immature within the UK and at the initial costing stage the costs will not be accurate until much later in the project lifecycle. In line with our original submission, we recommend applying a standard uplift of 6% to each project during the initial costing phase. This provisional measure would allow for early-stage budgeting while acknowledging the current uncertainty in biodiversity cost forecasting. We further propose that this uplift be reviewed at the midpoint of RIIO-T3, by which time we expect to have greater clarity on actual biodiversity scheme expenditures.

14.4.5 It is important to highlight that in Scotland, the specific value or threshold for Biodiversity Enhancement is not defined in the same way as for England, and a quantified target may never be forthcoming. The National Planning Framework 4 (NPF4) refers to a requirement for 'significant enhancement' rather than the 10% minimum gain mandated in England. Given this ambiguity, we seek assurance that where local planning authorities in Scotland require Biodiversity Enhancement exceeding 10% (as measured by the chosen metric tool), the associated costs will be fully funded under the forthcoming regulatory framework.

14.4.6 There is a need to continue to collaborate to develop appropriate funding mechanisms and processes for biodiversity enhancement in advance of Ofgem's FD and we welcome the inclusion of this topic in the scope of Ofgem's CSWG17 Environment working group.

14.5 LEI Funding

14.5.1 We are disappointed that the scope of the LEI funding has not been expanded within the current framework to enable us to deliver meaningful environmental and social benefits for local habitats and communities.

14.5.2 Regarding the reallocation of our LEI costs to the Net Zero Fund, we respectfully recommend that the NZF is allowed to align with the parameters of the LEI to provide direct funding investment to community projects. As outlined in the Draft Determination both NGET and SHET propose to use the LEI for funding programmes open to communities, this alignment would provide an equitable approach for communities across Transmission areas.

14.6 Environmental Reopener

14.6.1 We are disappointed that our request for a dedicated environmental reopener has not been accepted. While we acknowledge Ofgem's suggestion to utilise the Net Zero reopener where appropriate, we must emphasise that not all changes in environmental legislation are directly related to Net Zero objectives.

14.6.2 For example, a potential ban on glyphosate-based weedkillers during the price control period would not fall under the Net Zero remit. The alternative treatments currently available are less effective, necessitating more frequent site visits and thereby increasing operational costs. In such cases, the Net Zero reopener would not provide a suitable mechanism for cost recovery.

14.6.3 We therefore request that the scope of the Net Zero reopener be broadened in line with Ofgem's DD proposals to add new areas, and its name revised to reflect inclusion of environmental policy changes. This would ensure that unforeseen legislative or regulatory developments with cost implications, whether or not they are directly linked to Net Zero, can be appropriately managed within the regulatory framework.

14.7 Operational Transport PCD

14.7.1 We welcome Ofgem's recognition of the importance of decarbonising fleet and operational activities as part of achieving companies' science-based targets. However, we would encourage

that the criteria set within the Price Control Deliverable (PCD) framework allow for a degree of flexibility, to ensure that network companies are not unfairly penalised due to factors beyond their control.

14.7.2 It is important to acknowledge that each network company operates within a unique geographical and operational context. As such, a solution that is viable for one company may not be appropriate or feasible for another. Furthermore, even if one company is able to secure a suitable low-emission vehicle, this does not guarantee availability for others, as market supply and production line constraints may vary significantly.

14.7.3 We therefore request that these considerations be reflected in the design and assessment of the PCD to ensure a fair and practical approach to decarbonisation across the sector.

14.7.4 Our response to Ofgem's request for further information in this area to develop the PCD can be found in Annex 5.15, which is our updated EJP - RIIOT3 GS EJP2 FLEET.

Table 14-1 - Information request mapped to document

Information Request	Where to find
Why certain vehicles are not appropriate for individual network companies' operations	EJP Section 2.3
Breakdown of Category of Vehicles	Annex 7.3 Operational Transport PCD data sheet request Excel Sheet.
Expected number of each vehicle	Annex 7.3 Operational Transport PCD data sheet request Excel Sheet.
Unit costs	Annex 7.3 -Operational Transport PCD data sheet request Excel Sheet.
Supporting commentary on unit costs	EJP Section 4
Commentary for each vehicle category where ZEVs are considered not operationally viable.	EJP Appendix B & Annex 7.3 Operational Transport PCD data sheet request Excel Sheet.

ENVIRONMENTAL SUSTAINABILTY QUESTIONS

OVQ 2 Do you agree with our proposed position on the Environmental Action Plan and Annual Environmental Report ODI-R for RIIO-3?

We welcome the adoption of the Annual Environmental Report (AER) for RIIO-T3 and expressed our support for this in the SSMD. We are pleased to see its alignment with RIIO-ED2 guidance and will engage with the relevant Working Group to review the related AER Guidance. Additionally, we appreciate Ofgem's commitment to reviewing the AER on an annual basis, as this provides a valuable mechanism for holding network companies accountable.

We welcome Ofgem's flexible approach in enabling network companies to broaden the scope of the Annual Environmental Report (AER) to include wider sustainability topics. However, we would like to suggest that any page limit applied to the AER should pertain solely to the core content specified within the AER guidance. Where companies choose to report on additional sustainability areas beyond those outlined in the guidance, we recommend that such supplementary content not be subject to the page limit.

However, we seek further clarification on how 'holding to account' will be interpreted in practice, as it would be inequitable to penalise a company that has set a more ambitious target for a particular KPI, which will be more challenging to achieve, compared to one that has adopted a more conservative approach. Comparison of environmental and sustainability KPI's is also challenging due to a number of variables including scale of operation, geographical differences, differing timescales for commitments/strategies etc, and the difficulty to normalise effectively.

OVQ 3 Do you agree with our consultation position to create a new common mechanistic PCD for ZEV and associated infrastructure costs?

We recognise the potential customer benefits of introducing a Price Control Deliverable (PCD) for Operational Transport Emissions Reduction. While we welcome the value a PCD could bring, we remain concerned about the uncertainty surrounding the availability of certain vehicle classes, range, payload and operational resilience in high demand periods such as faults and storms. It is important that network companies are not unfairly penalised due to limitations in market supply, and it is not at all clear to us how Ofgem will '*consider how the outputs can be defined to allow suitable flexibility for companies to overcome the risk of market constraints in RIIO-3'*.

We understand the intention to benchmark performance across the sector, however, it is essential to acknowledge that each Network Operator operates within distinct geographical and operational contexts. As such, any benchmarking must be approached with care to ensure fairness and accuracy. Such comparison will be delivered via Ofgem's proposed review of the AERs. It's important that Ofgem works with network companies when producing the guidance for this area within the AER, to ensure comparison is fair and robust.

We request that the term 'Zero Emission Vehicles' is avoided, particularly in relation to this proposed PCD. Our Commitment is to '*Decarbonise our fleet by 2030 - electrifying 100% of feasible vehicles and implementing lower carbon alternatives for all other vehicles (where an electric alternative is not feasible for operational or technological reasons)*'. In addition, some stakeholders do not like this term as it can be considered to have elements of 'greenwashing', since fully electric vehicles are only 'zero emission' at tailpipe. We suggest 'lower carbon vehicles' would be more appropriate.

Our fleet is leased and as such our vehicle costs are opex and not capex. BPDT 11.8 V&T Memo, can also be found in Annex 5.15. This will need considered with respect to Ofgem's proposals in paragraph 4.24 regarding baseline cost allowances being set "only for capex".

It is essential for network companies to contribute to the development of this PCD and would request that there is ongoing engagement with the Network Operators via the appropriate Ofgem Working Group with agreed outcomes prior to FD.

We have provided the information requested by Ofgem in the DD in the above referenced EJP and Ofgem's data sheet request template. While we acknowledge Ofgem's intention to use this information to establish unit cost rates, we wish to emphasise the importance of maintaining flexibility in these rates throughout the price control period. The market for low-emission vehicles remains highly volatile and costs can fluctuate significantly over a five-year horizon due to technological advancements, supply chain dynamics and evolving operational requirements.

It is also impractical to apply a uniform unit cost across all network companies. Each company operates under distinct conditions and may identify specific vehicle solutions that best meet their operational and environmental needs. A vehicle that is optimal for one network may not be suitable for another, due to differences in geography, infrastructure and service models. Procurement processes and size of total contracts can also impact on prices negotiated.

Imposing a single unit rate risks undermining the core objective of this PCD, which is encouraging network companies to reduce Scope 1 emissions. If a network company cannot identify a suitable vehicle that aligns with both the standardised unit rate and its operational requirements, it may be forced to continue using internal combustion engine (ICE) vehicles longer than necessary.

We therefore strongly advocate for a flexible approach to unit cost setting, allowing for periodic review and adjustment to reflect market realities and support tailored, effective decarbonisation strategies across the sector.

ETQ 9 What are your views on our consultation positions for the TOs' EAP commitments in RIIO-ET3?

We welcome Ofgem's proposal to accept a substantial portion of our Environmental Action Plan (EAP) Commitments without amendment and remain committed to continued collaboration in the development and delivery of sustainable outcomes for the transmission network.

In relation to Ofgem's proposed amendments that are not the subject of specific consultation questions, we provide the following observations:

1. EAP Cost Increases – Paragraph 3.79

We agree with Ofgem's analysis of the factors driving the increase in EAP-related costs from RIIO-T2 to RIIO-T3. However, the introduction of new regulatory requirements mandating biodiversity enhancement of 10% in biodiversity in England and 'significant enhancement' in Scotland (Scottish Government Draft Planning Guidance: Biodiversity), go beyond the 'no net loss' standard applied in RIIO-T2 and represent an additional significant shift in expectation and scope for environmental stewardship.

2. Delivery of Net Zero 2035 Targets

We note Ofgem's support for our science-based Net Zero 2035 target. In response to the observation in the SPT Annex regarding delivery transparency, we refer to the following sources:

- The **Capital Carbon Plan** submitted as a Supplementary Document. This document has been amended for clarity following DD and can be found in Capital Carbon Annex
- The funding provisions set out in **Section 8.12 of the Net Zero BPDT.**

These documents include measures relating to Low Carbon Construction Materials and Opportunities under the proposed UIOLI mechanism, whilst also outlining the strategic pathways, investment framework and associated activities that will enable progression toward our Net Zero target.

- Please refer to **BPDT 9.17 Environment** which highlights the initiatives we propose for RIIO-T3 to reduce our BCF

- We also now provide our SPEN Net Zero GHG Transition Plan (which was under production at the time of the RIIO-T3 BP Submission and has now been finalised) see Annex 7.1

3. Business Carbon Footprint and Losses – Paragraph 3.102

Ofgem raises an important point regarding the inclusion of electricity losses in Business Carbon Footprint (BCF) metrics, particularly in the context of grid decarbonisation. The suggestion that this inclusion may distort performance indicators for more directly controllable emissions warrants further engagement and development with Ofgem.

Under the Science-Based Target Initiative's established rules, electricity losses are classified as Scope 2 emissions for electricity network operators. We have consistently reported our BCF both including and excluding losses, in the interest of transparency and alignment with recognised standards. We welcome further engagement to ensure clarity on this matter and to address any underlying concerns about attribution or performance comparability.

4. Resource Use, Waste and Circular Economy

While Ofgem has accepted our commitments in this area without amendment, citing minimal direct costs, we wish to stress that their successful implementation is contingent upon funding for carbon reduction initiatives via the Low Carbon Construction UIOLI. Many of the activities targeted under this scheme deliver co-benefits including enhanced circularity and improved resource use efficiency. As such, our commitments should be viewed as integrally linked to our broader carbon reduction strategy.

ETQ 11 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 are pleased with Ofgem's support for a Biodiversity Enhancement requirement of 10% (minimum), recognising that this aligns with the English legislative requirements and is a reasonable prediction of the Scottish NPF4 'significant enhancement' standard that will be required to secure planning permission. It is important to note, however, that planning authorities in Scotland may require biodiversity enhancements in excess of 10% to grant consent. In this context, we wish to identify that the statement in paragraph 3.115 "For SPT and SHET, this is more than the legislative requirements of delivering a 'positive effect' in Scotland" does not accurately reflect the Scottish situation. In practice, demonstrating a 'positive effect' under Scottish legislation may necessitate biodiversity enhancement in excess of 10%. Accordingly, we seek confirmation that in instances where local authorities require measures beyond the 10% threshold, the additional associated costs will be eligible for funding.

Furthermore, we are concerned regarding the proposal for TOs to develop biodiversity-related costs upfront for assessment within overall project costs. Biodiversity requirements can only be accurately quantified following detailed site assessments, stakeholder consultation and ecological evaluations. As such, early-stage cost forecasts are subject to considerable uncertainty. Flexibility will therefore be required within the cost assessment process to accommodate this variability by allowing finalisation of costs later in the process, reflecting the evolving nature of biodiversity enhancement obligations and ecological planning standards. If this is to be the approach, we therefore reiterate the proposal in our original submission that an uplift of 6% be applied to initial project costs until more accurate costs are known through the project

lifecycle (which may be greater than the 6%). This level of uplift could have a mid-period review to establish whether this is still appropriate when more information on biodiversity enhancement costs has become available.

We draw attention to a market-driven cost pressure: as biodiversity enhancement becomes a mandated requirement across all developments seeking planning permission, the availability of land on which offsite biodiversity enhancement can be delivered will diminish. This scarcity is expected to drive up the unit cost of biodiversity enhancements over time. The process to be employed to fund biodiversity enhancement requirements must be able to accommodate these potentially extremely variable costs which are difficult to forecast.

Access to separate funding (to that for scheme delivery) is required for the development of a pipeline of biodiversity enhancement schemes in order to ensure the availability of enough biodiversity enhancement of the correct type (of habitat) in the required locations at the required time (for projects). We are reliant on external partner organisations to deliver the offsite enhancement, but we cannot rely on them developing potential schemes that will meet all of these criteria in advance of our need. They will require financial support to ensure that they develop/scope out the schemes that we will need. This has been a learning from the delivery of our RIIO-T2 UIOLI biodiversity initiatives. As Ofgem has indicated that they are looking to fund project-specific biodiversity enhancement requirements when they are identified, this does not allow for the advance funding of scheme pipeline development. This would be a relatively small value compared to scheme delivery costs. We request that this consideration is included in the ongoing discussions of the CSWG17 Environment.

As highlighted in discussions of the CSWG17 Environment Working Group, it may sometimes be necessary to deliver biodiversity enhancement schemes that exceed the proposed RIIO-T3 minimum 10% target i.e. it may not be possible to size the scheme to conveniently fit the enhancement requirements of a particular SPT project. It may be more cost-effective and operationally efficient and/or arise as a result of the needs of the delivery partner or landowner with whom we must agree the enhancement schemes. It is expected that such schemes will become requirements of the project planning consent in any case, where that is applicable, but it is important that Ofgem is aware of this important point.

In addition to the above, biodiversity enhancement costs can vary significantly across regions, further complicating attempts to benchmark across projects. We therefore seek Ofgem's recognition of these factors and request that they are factored into Ofgem's considerations of TOs' proposals for biodiversity enhancement.

Funding mechanisms must also be flexible enough to allow investment in landscape scale schemes that align with national nature targets and support connectivity of habitats (nature networks) and may meet some of the biodiversity enhancement needs of multiple SPT projects. Such schemes are likely to be very cost-efficient.

We acknowledge the ongoing debate regarding the appropriateness of consumers funding biodiversity enhancement that 'exceeds statutory requirements' (in Ofgem's DD terminology this refers to projects that do not require planning consent). It is important to recognise that TO projects can have significant and lasting impacts on the local environment, regardless of whether they require planning consent with the associated 'significant enhancement' and 'positive effects' requirements in Scotland's NPF4. In cases where formal planning obligations do not apply, e.g. where planning consent is deemed under 'permitted development' rights, biodiversity will in many cases still be adversely affected.

As TOs are called upon to deliver an unprecedented level of infrastructure investment in support of achieving the UK's target for Net Zero, it is essential that this progress does not come at the expense of the natural environment. This is also part of Ofgem's Net Zero Duties. Moreover, the protection and restoration of biodiversity is intrinsically linked to climate change, climate resilience and long-term

sustainability. Reducing the impact of development on biodiversity is no less critical than reducing greenhouse gas emissions. A thriving natural ecosystem underpins the very conditions that make life on Earth possible. As such, investment in biodiversity should be recognised not solely as a regulatory obligation but as a core component of responsible infrastructure delivery towards a Net Zero future. This is also the view and the expectation of stakeholders, who will not distinguish between projects that require planning consent and those that don't (e.g. underground cables, reconductoring of OHLs). We therefore consider it both proportionate and necessary to ensure biodiversity mitigation and enhancement is embedded within all projects where there is a measurable impact on nature. Our stakeholders have told us they support this position. We therefore request that the conditions for funding of biodiversity/natural capital enhancement are not limited to projects requiring planning consent. Before Final Determination we ask that Ofgem works with network companies to fit biodiversity enhancement into the current regulatory process. SPEN are already working with NGET and SSEN-T on this topic.

ETQ 23 What are your views on our consultation position for the LEI UIOLI in RIIO-ET3?
Whilst we acknowledge the rationale behind the decision to reduce the allowance available to us[285], recognising that the current area definition, (which is limited to national parks), has limited our ability to utilise it effectively within our operational boundaries. We are nonetheless disappointed that the scope of this mechanism has not been expanded, as per Ofgem's WG discussions, to encompass a broader range of defined/designated sites. Such an expansion would have enabled us to deliver more meaningful and positive landscape outcomes within our area. We request that Ofgem reconsider an extension to include temperate rainforest and peatland sites, so that we can effectively utilise this fund, as without a expansion of the definition this fund is useless to us, and therefore offering this fund to us while knowing we cannot utilise it brings no value.

Please see our response to SPT1 Q1 in regards to the Net Zero Fund which the scope has been diluted from community benefits to capacity building only. As noted the LEI fund, which we have been unable to use, has been used by both NGET and SHET to provide grants for community funding, using the Net Zero Fund for community grants would ensure consistency of application across TOs.

ETQ 42 Do you agree with our proposed Carbon Compensation UIOLI to fund carbon offsetting in RIIO-ET3?

We support the inclusion of carbon offsetting as a necessary mechanism to enable TOs to meet their science-based targets. The ability to begin offsetting residual emissions within the forthcoming price control period will be instrumental in progressing toward our Net Zero goal by 2035.

We support the alignment of offsetting policy across the sector and have already drafted a robust governance approach to ensure the use of high-quality offsets and commenced engagement with the other TOs on this issue.

ETQ 43 Do you have any views on our proposal to reject these two environmental UMs?

Low Carbon Construction Materials and Opportunities UIOLI

285 RIIO-3 DD – Electricity Transmission : 3.250 SPT's use of the UIOLI in RIIO-ET2 has been restricted because its operating area is not close to the relevant National Scenic Areas or National Parks of Scotland. As a result, they envisage their ability to utilise the fund in RIIO-ET3 will also be limited. 3.254 Following the discussion with SPT we considered proposing to expand the scope of the LEI to include improving the biodiversity of rainforests, but we have elected not to do this. The rationale behind the expansion would have been to broaden the ability of the Scottish TOs to make full use of the allowance. Scotland's rainforest zone, and the work to be done on its biodiversity wellbeing, made it an attractive area for consideration. However, we recognise the impact that transmission infrastructure can have on the visual appearance of areas of particular natural beauty is a significant concern for local communities and users of those environments, and that expanding the scope to cover rainforests would potentially shift the LEI away from its core focus from infrastructure mitigation.

We believe it is important to point out that without funding for higher cost lower carbon solutions (with appropriate controls) we will not be able to achieve our carbon reduction targets, which Ofgem proposes to accept.

Following the recent DD outcome, the Department for Energy Security and Net Zero (DESNZ) has published a new consultation titled "Growing the Market for Low Carbon Industrial Products: Policy Framework." This consultation, with an initial focus on steel, cement, and concrete, clearly demonstrates the UK Government's commitment to promoting the use of low carbon materials and products within the construction sector and outlines its intention to support this ambition through a structured policy framework. The products are critical elements for new substation (e.g. foundations, structures) and overhead line builds (e.g. towers).

Whilst no decision has been made (consultation closes Sep 2025) it sends a strong signal to Ofgem regarding the importance of enabling and encouraging network companies to procure low carbon alternatives in their infrastructure projects. Green procurement expenditure has the potential to shape the market and if strategically directed could help increase demand for low carbon products and support the transition to a low carbon economy. As the sector continues to expand rapidly, it is essential that regulatory mechanisms align with national decarbonisation goals and support the industry in meeting its greenhouse gas reduction targets.

On the basis of several of Ofgem's comments within the DD, we believe our justification for the basis of this funding request and its quantification of costs and benefits to the consumer have not been fully understood by Ofgem and therefore we provide clarified justification within our Capital Carbon Annex.7.2 We strongly urge Ofgem to reconsider the position on the two proposed UIOLI allowances.

In particular, we now include additional justification for our proposed 1.4% uplift on project costs and identification of a cost-efficiency threshold to ensure consumer value, which Ofgem specifically mentioned as missing items. We also note that we made no reference to EGL2 costs in our submission, as this is not our project, and believe that Ofgem have referred to this erroneously in their RIIO-T3 DD, with respect to SPT.

We continue to believe that an overarching UIOLI type fund will provide the greatest flexibility and efficiencies to facilitate delivery of the required carbon emissions reductions at the lowest cost to consumers. The low carbon construction materials market is immature, the UIOLI fund will provide the opportunity to stimulate the market and provide certainty of their order book, much like the APM, this will allow orders to be placed in bulk rather than on a project-by-project basis. We believe this will allow innovative solutions to be developed and based on economies of scale and efficiency reduce costs for consumers in comparison to a piecemeal project by project approach in the cost assessment phase. To protect consumers the use of the UIOLI fund will be reported for assessment of costs incurred and any unused funds will be returned.

Due to the immature nature of the market for low carbon solutions, there will be limited information available early in the project design stages resulting in few low carbon solutions meeting the cost assessment criteria at that stage and therefore less carbon reductions being delivered. Unless greater flexibility is provided within the project cost assessment process (see further comments below). Our carbon reduction target is an overarching target, not a project specific target, and as such an overarching fund will also allow us to target carbon reduction expenditure where it delivers the most cost-effective reductions, prioritising action on some projects over others. We request that Ofgem reviews the clarified justification in our Annex 7.2 and reconsider our proposal, as we believe the concerns identified in the DD are addressed therein. We would be pleased to be involved in ongoing discussions on this via the relevant Ofgem WG.

In the situation that Ofgem's favoured option remains the requesting of funding for low carbon materials within project costs, we identify that this approach can only apply to projects where costs have yet to be requested such as those submitted under the RIIO-T3 load and non-load re-openers.

As a result, unless there is scope to retrospectively adjust cost allocations, baseline projects already included in the business plan would be ineligible for funding for low carbon materials and other opportunities. These costs were not originally included, as reliance was placed on the UIOLI mechanism to support such initiatives. We draw attention to the £5.68 million (representing 1.4% of non-load project plan costs) associated with these initiatives, as detailed in section 8.12 of the BPDT Net Zero submission.

Prior to FD (for either an overarching UIOLI fund or project specific funding options) there is a need to work collaboratively with Ofgem to agree on the approach for including allowances for low carbon technologies and low carbon materials within the new RIIO-T3 load and non-load re-openers cost assessment submissions. Within our BP we proposed justification for a 1.4% project uplift, split between low carbon materials (0.3%) and low carbon technologies (1.1%). Further clarity on this can be found in Annex 7.2.

In the case of project specific carbon reduction funding, we propose that where low carbon costs are included in project assessment submissions, , they are approved without further challenge. This would be governed and reported under the applicable re-opener mechanisms. It recognises our alignment with Ofgem's environmental objectives and the clearly identified environmental justifications in the project assessment. As projects mature, if these low carbon opportunities meet the customer value-for-money threshold as defined by the DESNZ carbon price then the funding is already available for use. If, however, any of the proposals do not meet the criteria, then the funding will not need to be used. This approach ensures that funding is used only where it delivers measurable carbon savings and value for customers, allows flexibility to adopt new low-carbon solutions as they become viable and minimises project delay by making funding available at project assessment.

We acknowledge Ofgem's proposal to utilise innovation funding in place of Pot 2 funding for emerging technologies. Where low-carbon solutions meet the criteria for innovation funding, we will pursue this route. However, it is important to note that technologies at the "off-the-shelf" stage regardless of whether they have been trialled by network companies do not qualify for innovation funding (under current innovation funding rules). Currently, there is no alternative financial mechanism available to TOs to support such technologies, which risks limiting the potential for initiatives aimed at reducing carbon emissions within the RIIO-3 framework.

The original intent behind Pot 2 was to enable TO investment in emerging technologies that often carry higher upfront costs. These technologies, while not qualifying as innovative under existing definitions, can deliver cost-effective carbon reductions. The fund was envisioned to allow TOs to pay a modest premium for lower-carbon options that are new to market, where suppliers are still recovering development costs and economies of scale have not yet been realised. In such cases, the carbon savings demonstrated in cost-benefit analyses would justify the additional expenditure.

We therefore reiterate the need for a Use-It-Or-Lose-It (UIOLI) mechanism, which provides TOs with the flexibility to deploy lower-carbon solutions as they become available during a project's lifecycle. Given the long lead times and complexity of transmission projects, from initial design to construction, this flexibility is essential. It ensures that TOs are not constrained by the need to identify and cost every potential low-carbon solution at the outset, enabling more responsive and sustainable decision-making throughout project delivery.

Carbon Border Adjustment Mechanism Reopener

We agree with Ofgem's proposal to include CBAM in the Net Zero Reopener, which will require explicit reference to CBAM in a revision to its scope.

ETQ 69 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?

Ofgem must give due consideration to all of a transmission licensee's statutory duties. We do not "*refer to consenting or project cost justifications"* (5.182). We give due consideration to our statutory duties, which include our duty under the Electricity Act to develop and maintain an efficient, coordinated, and economical system of electricity transmission.

Ofgem state in 5.184 that "*F-Gas technology replacements to potentially be undertaken at lower whole life costs" without providing justification of when and why this would be necessary nor providing evidence to support their cost argument*". We note, as Ofgem will be fully aware from our EJP submissions for RIIO-T3 and before, that holistic approaches to asset interventions result in the best outcome for consumers.

We comply with the F-gas regulations, reduction of the carbon impact of F-gases is an SPT objective and is weighed against its other statutory duties. Ofgem's regulatory frameworks must also consider other duties and note that these may often be in tension. We strongly agree with paragraph 5.186 and note that it is consistent with our business plan and previous regulatory submissions.

SPTQ 7 Do you agree with our proposal to reject SPT's Environmental Re-opener?

We do not support the proposal unless the scope and the name of the Net Zero reopener are revised to accommodate Ofgem's proposal to include the proposed scope of our Environmental Reopener in that existing Reopener. The current framework does not adequately reflect the broader range of environmental legislative and regulatory changes that could significantly impact our operational costs. Labelling it as a "Net Zero" reopener implies a narrow carbon emissions focus, whereas environmental legislative and regulatory changes that could come into effect, such as potential restrictions on the use of certain chemicals in weedkiller, may have no direct link to Net Zero objectives or carbon emissions but could still lead to increased environmental impacts such as resource consumption, and an increase in costs. To ensure clarity and alignment, we request that the Net Zero Reopener be renamed and redefined accordingly to encompass the wider scope of environmental regulatory changes covered by our environmental reopener request. This re-opener should also have the ability to be triggered by the TO and not only the authority.

In respect to the need for the reopener for visual amenity the Scottish Gov published the decision on the National Park proposal, and this will not progress in our operational area at this time. Nonetheless we remain of the opinion that Ofgem must consider the potential impact of environmental policy changes by Local Authorities, the Scottish Environment Protection Agency and other relevant regulatory bodies.

Chapter 15 - Community Benefits and Net Zero Fund

15.1 Community Benefits

15.1.1 Community Benefits funding is in line with expectations; we agree with the funding pass through mechanism however we have concerns with the 10% maximum limit on delivery costs. Since the launch of the UK Government Community Funds for Transmission Infrastructure guidance in March 2025 we have communicated to DESNZ and Ofgem that delivery costs to implement Community Benefits, in line with the guidance, will exceed 10%.

15.1.2 Through the implementation of community funding programmes in the previous two price controls we have evidence of actual delivery costs required to implement community funding and capacity building support, as outlined in the UK Government Community Funds for Transmission Infrastructure guidance.

15.1.3 We welcome ongoing discussions with DESNZ and Ofgem to agree the methodology to successfully deliver funding and capacity building support to communities hosting transmission infrastructure projects.

15.1.4 We accept that administration of a fund can be capped to 10%. We suggest other delivery elements, such as staff costs, feasibility studies, capacity building, etc, are "built up from first principles, with resourcing costs itemised rather than based on fixed rates or percentages of overall project cost and are efficient and economic" as stated in the Government Guidance (p.8). We would also expect Ofgem's position to be in full alignment with the government guidance which would allow costs for 'exceptional circumstances'. However, the Draft Determination appears to omit any allowance for exceptional circumstances when a community may require more support from a Transmission Owner in developing their community fund package.

15.1.5 We would welcome clear and timely guidance from Ofgem on the specific information, data, and reporting requirements for Transmission Owners (TOs), both ahead of the FD and throughout RIIO-T2 and RIIO-T3. This will help ensure transparency, consistency, and successful delivery of Community Funds.

15.1.6 Greater clarity on how costs will be assessed and assured would be appreciated, particularly to provide confidence that TOs will not be subject to retrospective penalties due to evolving or unclear criteria.

15.1.7 We encourage Ofgem to align Community Funding figures with UK Government guidance to avoid confusion for communities. Ensuring consistency in indexation and documentation.

15.2 Net Zero Fund

15.2.1 We are disappointed by Ofgem's decision to not allow the Net Zero Fund to provide direct funding support to communities. The Net Zero fund, as set out in our business plan, was well supported by key stakeholders including communities and our ISG (Independent Stakeholder Group). The ISG are strong advocates for this fund, having witnessed first-hand the difference that providing much needed funding can make.

15.2.2 Limiting funds to capacity building reduces the likelihood of projects coming to fruition, threatening vital support for vulnerable communities in central and southern Scotland and risks losing a projected social return of **£3.10 return for every £1 invested**[286].

15.2.3 Delivering funding directly into local communities is not only something expected from every other network company, but is also already a part of the RIIO-T3 framework through the Landscape Enhancement Initiative and Community Benefits funding. NGET also offer its communities a Community Funding programme. We absolutely see it as our responsibility to provide Community Benefits to areas hosting new infrastructure, while also supporting those communities not eligible for such benefits, particularly the most vulnerable in society who may nonetheless be affected by

[286] RIIO-T3 Business Plan page 55: https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T3%20Business%20Plan%20-%20SP%20Energy%20Networks%20-%20Website%20-%20December%202024.pdf

our works that fall outside the Community Benefits criteria. This will ensure that communities are able to benefit from a fair and Just Transition.

15.2.4 Through delivery of our RIIO-T2 Net Zero fund we have experience and evidence of the positive impact this funding provides to vulnerable communities, delivering a Just Transition in our network area. Our communities have told us this support was not available from other sources.

15.2.5 We welcome Ofgem support for Net Zero capacity building in communities. Capacity building is essential, as part of a funding support package, **to help vulnerable communities realise their net zero ambitions**.

15.2.6 Providing technical expertise and sharing knowledge inspires communities to develop projects capable of delivering widespread benefits in their area. However, through our experience we know that funding and ongoing support through the project delivery phase is the **crucial element** in ensuring projects come to fruition and are successfully delivered.

15.2.7 In summary, through delivery experience we know that funding support is required to demonstrate measurable outcomes. Capacity building alone will not deliver a measurable social return on investment.

15.2.8 We suggest, if there are residual concerns about the allocation of funding from the Net Zero Fund, additional controls from Ofgem could be considered, for example enhanced reporting, the mandating of independent decision making, an oversight role for the Independent Stakeholder Group or alignment with existing funding provided by other TO's. We would welcome further controls and discussion with Ofgem to ensure that we are able to continue to deliver value to our communities through the Net Zero Fund.

COMMUNITY BENEFITS and NET ZERO QUESTIONS

ETQ 8 Do you agree with our proposed design of the Community Benefit Funding pass-through mechanism?

We welcomes Ofgem's endorsement of the UK Government's guidance on Community Funds for Transmission Infrastructure[287]. We recognise that new infrastructure can impact those living in proximity. That is why we committed in our RIIO-T3 Business Plan to work in partnership with communities to deliver social, economic and environmental benefits that will leave a positive legacy on our impacted communities fund.

We appreciate that the DD sets out clear mechanisms through which TOs can deliver meaningful benefits to communities hosting network infrastructure.

We would also like to acknowledge and commend Ofgem's proactive engagement on this matter over recent months. However, despite this constructive dialogue, several areas remain ambiguous and require further clarification from Ofgem urgently. We have detailed our views below.

Ofgem and DESNZ administrative and delivery costs are not achievable.
We are deeply concerned with the 10% (non-index linked) limit on delivery costs. This is an arbitrary figure which does not align with our bottom-up analysis of estimated costs. This will severely restrict and limit the level of engagement and support that can and should be provided to communities and risks non-delivery of the UK Governments guidance which aims to develop Community benefits "**with** communities... and that are **tailored** to their needs". This does not align the original policy intent outlined in the Nick Winser recommendations in 2023 and potentially dilutes the impact of community benefits especially to hard-to-reach community groups including vulnerable consumers. Since the publication of the UK Government's guidance on Community Funds in March 2025, we have consistently communicated to both DESNZ and Ofgem that the costs associated with delivering community benefits in accordance with this guidance are expected to exceed the 10% threshold. We would also expect Ofgem's position to be in full alignment with the government guidance which allows costs for 'exceptional circumstances'. However, the DD appears to omit any allowance for exceptional circumstances where a community may require more support from a TO in developing their community fund package. We therefore urge Ofgem to reconsider this limitation to ensure that the intended outcomes for communities can be fully realised.

We accept that third party fund administration can be capped to 10%.
However, the exhaustive list of additional delivery costs, including resourcing, capacity building and feasibility studies, over and above administration of the funds, makes the cap unachievable. It would particularly impact local communities who wish for capacity building or feasibility studies to be undertaken – but will find themselves restricted because purely administering the funds will use up all of the 10% allowance.

Through our valuable experience in implementing community funding programmes in RIIO-T1 and RIIO-T2, we have evidence of actual delivery costs required to implement community funding and capacity building support, as outlined and expected in line with the UK Governments guidance. This bottom up analysis, even with considering the provision for delivery costs exceed the 10% threshold in exceptional circumstances, this allowance remains insufficient to reflect the actual administrative costs required in practice. As per previous dialogue with Ofgem we have considered economies of scale in our calculations and estimate delivery costs between 18.5% and 20.5% of funding values.

We welcome ongoing discussions with DESNZ and Ofgem to agree the methodology to successfully deliver funding and capacity building support to communities hosting transmission infrastructure projects. To support Ofgem's decision making we have outlined a breakdown of delivery costs associated with the successful deployment of our previous Green Economy Fund and RIIO-T2 Net Zero Fund.

[287] **Community Funds for Transmission Infrastructure**
https://www.gov.uk/government/publications/electricity-transmission-network-infrastructure-community-funds/community-funds-for-transmission-infrastructure-accessible-webpage

We accept that third party fund administration should be capped to 10%. We suggest other delivery elements, points 2 to 5 below, are "built up from first principles, with resourcing costs itemised rather than based on fixed rates or percentages of overall project cost and are efficient and economic" as stated in the Government Guidance (p8).

Delivery Cost breakdown calculated through experience of delivering the Green Economy Fund, the RIIO-T2 Net Zero fund and latest marketed tender activity:

Table 15-1- Cost Breakdown of Green Economy Fund

1	7%	Third party administrator	First tender for Community Benefits has been to market and awarded to lowest cost compliant organisation. Economies of scale will not be significant enough, given each additional £1m of funding will still require the same contractual attention and robust due diligence.
2	5-7%	Resourcing	Fund and contract management, Community engagement, Communications, Governance and Reporting. Scaled up from experience and down based on forecast efficiencies.
3	1%	Capacity building	Events, workshops, resources and the development of community plans.
4	2%	PR and marketing	Mail shots, media, project case studies, reports and design. Scaled back through forecast efficiencies given higher fund values.
5	3.5%	Feasibility	Through experience of delivering the RIIO-T2 NZF we can evidence feasibility study costs equating to an average of 7% of project costs. However feasibility studies are not always required e.g. where communities have well developed projects or projects are non-technical. We anticipate 50% of projects funded will require feasibility, therefore estimate feasibility costs at 3.5% of total community funds

Clarity is required on what specific information and data is required from Ofgem.
In line with Ofgem's direction, we included relevant information and a breakdown of associated costs within our Environmental Action Plan as part of our RIIO-T3 Business Plan submission. As previously communicated to Ofgem this material was prepared prior to the UK Governments guidance in March 2025. We urge Ofgem to provide definitive guidance to ensure that Community Funds are structured for success and that Ofgem has a transparent and comprehensive understanding of how these funds will be delivered.

Conflicting indexation figures will create confusion for communities
As per DESNZ guidance community funds will not be indexed linked to avoid unintended electricity bill impacts and recommend funding values of £200,000 per km of overhead line and £530,000 per substation etc. Within Ofgem's proposed licence conditions the figures differ noting £195,320 per km of overhead line and £517,598 per substation. Through dialogue with Ofgem it has been confirmed that this is due to indexation and that the prices presented in the licence are in 23/24 prices to align with business plan submissions. To avoid any unnecessary ambiguity Ofgem should ensure that all community funds are documented consistently with the UK Governments guidance.

Pass through mechanism
We acknowledge Ofgem's proposed Pass through mechanism and note that it aligns with our expectations. However, further clarity is required regarding the timing and process for reporting costs in particular for costs associated with projects eligible for community funds in the RIIO-T2 period which will ensure that we are set up for success for the commencement of RIIO-T3.

Reporting
We welcome Ofgem's DD that TOs should submit an annual break down of the delivery costs annually via Regulatory Reporting Pack (RRP) process. We will continue to work closely with Ofgem and across the other TOs to ensure consistency in reporting. It will be critical for Ofgem to provide clear and detailed guidance on the format and specific information required within the RRP to support transparency and consistency.

Cost Assessment
In relation to cost assessment, the UK Governments guidance indicates that *'The Transmission Owners must demonstrate to Ofgem that administrative costs have been built up from first principles and are efficient and economic, in order for the costs to be recoverable.'* Whilst Ofgem's DD signpost that Ofgem *'do expect to need to have to review the administrative cost…'* and that Ofgem will not assess the main community funds. It remains unclear what methodology Ofgem will apply to their cost assessments. Each of the three TOs have developed distinct processes and programmes for deploying their respective Community Funds. This variation introduces uncertainty around how Ofgem intends to assess or benchmark each TO's approach. We therefore seek clarity on how Ofgem will evaluate these funds, particularly given the bespoke nature of each programme, and how such assessments will align with the UK Government's guidance on ensuring economic and efficient delivery. We also request further guidance on how Ofgem intends to apply these principles in practice, recognising that traditional cost-benefit analysis may not be appropriate or applicable in these instances.
It is imperative that Ofgem provides urgent clarity on this matter which will provide TOs confidence to continue to invest in community funds without the uncertainty and risk of retrospective clawbacks based on ambiguous or undefined criteria.

SPTQ1. Do you agree with our proposal to retain the Net Zero Fund UIOLI for SPT, and with our proposed parameters for it?

We welcome Ofgem's commitment to support communities ineligible for Community Benefits through retaining the Net Zero Fund (NZF) allowance and agree with the continuation of a UIOLI mechanism.

We are disappointed by Ofgem's decision to not allow the Net Zero Fund to provide direct funding support to communities. The Net Zero fund, as set out in our business plan, was well supported by key stakeholders[288] (including those that expressed support directly to Ofgem during the business plan call for evidence[289]) including communities and our ISG (Independent Stakeholder Group). The ISG are also strong advocates for this fund, having witnessed first-hand the difference that providing much needed funding can make.

Our Net Zero Fund criteria is focused on supporting vulnerable consumers[290]. This is in line with Ofgem's published consumer vulnerability strategy, most notably: *"All network companies should also work collaboratively to understand where there are broader gaps in approaches to protecting consumers in vulnerable situations."* [291] Energy access is a basic requirement for modern life and as we move toward a low-carbon future, it's essential to ensure that no one is left behind, especially those who have energy insecurity or are disproportionately affected by energy infrastructure.

[288] RIIO-T3 Business Plan – Environmental Action Plan https://www.spenergynetworks.co.uk/userfiles/file/Environmental%20Action%20Plan%20-%20RIIO-T3%20Business%20Plan%20-%20SP%20Energy%20Networks%20-%20Redacted.pdf
[289] Ofgem Call for Evidence Collated Responses https://www.ofgem.gov.uk/sites/default/files/2025-03/RIIO-3-Call-for-Evidence-collated-email-responses.pdf
[290] Matt Cole is a member of our ISG and chairs Scotland Fuel Poverty https://fuelpovertypanel.scot/who-we-are/
[291] See page 28 https://www.ofgem.gov.uk/sites/default/files/2025-04/Final%20CVS%2015042025-20250414111309.pdf published April 2025

Through the delivery of our RIIO-T2 Net Zero Fund, we have gathered clear evidence of the positive impact that targeted funding can have on vulnerable communities within our network area. These initiatives have supported a Just Transition 292 ensuring that the benefits of decarbonisation are shared equitably.

Our engagement with communities has revealed that this type of support is not available from other sources, highlighting a critical gap that transmission operators are uniquely positioned to fill. By targeting vulnerable communities, we help to:

- Address systemic inequalities in energy access and affordability.
- Empower local resilience through energy efficiency and low-carbon technologies.
- Deliver social value in line with Ofgem's expectations and community needs.
- Strengthen trust and legitimacy in our role as a responsible infrastructure provider.

We believe this is not just a strategic opportunity but an essential responsibility. As a Transmission Operator, we are active in our communities, have the resources, and can play a transformative role to ensure that no community is left behind in the transition to net zero.

We do **not agree** with the parameter set which prohibits direct funding of local community projects. Limiting funds to capacity building reduces the likelihood of projects coming to fruition, threatening vital support for vulnerable communities in central and southern Scotland and risks losing a projected social return **of £3.10 return for every £1 invested**[293].

We agree that capacity building is required to facilitate the delivery of successful projects, but do not consider that its value as a standalone intervention can be accurately measured.

We also note that in Ofgem's consultation there is an alternative view from Ofgem that the Net Zero fund can be used to fund community projects as we can no longer access LEI UIOLI funding (see response to ETQ23).

We suggest NZF parameters allow the funding of local projects which provide measurable environmental and social benefits in communities ineligible for community benefits. This is in line with NGET's Community Grant Programme. We propose that funding is only used to support projects where communities have no other source of funding available for the project. Each application will require to be assessed through an independent decision-making process and stringent internal Governance procedures to ensure projects provide Social Return on Investment (SROI) and best value to consumers in delivering a Just Transition.

In response to specific Draft Determination points:

1. RIIO-3 DD - SPT Scope point 2.12 states: "Consistent with our decision at RIIO-ET2 FD, we do not consider it appropriate for SPT (in its role as TO) to use an allowance provided for through the price control directly to fund consumer-proposed projects."

Response: We have engaged with Ofgem throughout RIIO-T2 to clarify the purpose and delivery methodology of our Transmission Net Zero Fund, including the provision of tailored support **and funding** for community projects as a last resort. However, there is a critical shift in policy direction and the role of the TO since RIIO-T2, following Nick Winser's recommendation in 2023 for communities to benefit from being in close proximity to electrical infrastructure and since the publication of the community benefits guidance. Ofgem's reliance on an outdated RIIO-T2 reference is invalid for the future of the net zero fund for RIIO-T3.

We do not agree that it is inappropriate for TOs to directly fund communities, but contrary to Ofgem's position, see the importance of us supporting the most vulnerable in society to ensure their communities are able to benefit from a fair and Just Transition.

292 SP Energy Networks website link - our just transition strategy
293 RIIO-T3 Business Plan page 55: https://www.spenergynetworks.co.uk/userfiles/file/RIIO-T3%20Business%20Plan%20-%20SP%20Energy%20Networks%20-%20Website%20-%20December%202024.pdf

We welcome and support the recent publication of the DESNZ guidance on "Community benefits for electricity transmission network infrastructure" and the impact this will have on communities hosting new transmission infrastructure. Allowing TOs to provide support for: projects that "enhance the local economy, society, and environment and to align with community priorities such as local tourism, education, and skills development opportunities". The NZF has a different scope to community benefits and should be able to provide support for communities ineligible under the DESNZ community benefit guidance in our operational area.

2. RIIO-3 DD - SPT Scope point 2.12 states "There are other public and private sector means through which community groups can seek direct funding for projects."

Response: Our RIIO-T2 Net Zero fund required communities to demonstrate in their grant applications that this was "**funding of last resort**". We therefore have an evidence base showing the NZF meets gaps in funding available to communities which are now facing the risk of being left behind on the country's transition to Net Zero.
Key themes evidenced by communities include:

1. Limited availability of capital grant funding that includes energy efficiency measures
2. Other funds are restricted to a percentage of project costs and require match funding (the NZF provided match funding which enabled communities to access other funding streams)
3. Reduction in Local Authority funding available. Significant pressure on Local Authority budgets reducing their ability to deliver projects and sustain community buildings.
4. Significant cost of Electric Vehicles, young technology (limited 2nd hand market)
5. Charities and community groups are unable to contribute using own reserves or through loan finance:
    - Limited unrestricted reserves in bank account
    - Unable to take out loans
    - Increases in operational costs (energy) and inflation
    - Decrease in income streams (paid users of buildings and charitable donations).

3. RIIO-3 DD – Electricity Transmission "3.255 - We propose to ..reduce the size of the LEI allowance by £5m for SPT to £6.6m. 3.257 - The £5m adjustment has been made to reflect the bespoke Net Zero Fund UIOLI providing SPT with £5m to support vulnerable communities within its licence area in their transition towards net zero"

Response: As outlined in the Draft Determination the purpose of the LEI is to make a positive contribution to wildlife, biodiversity, cultural heritage, the natural beauty, and public enjoyment in National Parks, National Scenic Areas and National Landscapes hosting existing electricity infrastructure.
Due to our network being limited in the specified areas we did not use the LEI fund in RIIO-T2 and have limited opportunity to use the RIIO-T3 allowance under the current scope of the mechanism.
In RIIO-T2, NGET used the LEI to deliver a £12m grant funding programme open to communities to directly fund projects. The RIIO-T3 DD states that SHET is looking to create a community access fund, structured similarly to the approach NGET takes for its LEI fund.

Furthermore, this aligns with NGET's RIIO-T3 Business Plan proposal for the continuation of their Community Grant programme, providing funding support to communities out of scope for community benefits but still impacted by infrastructure works.

We suggest, if there are residual concerns about the allocation of funding from the Net Zero Fund, additional controls from Ofgem could be considered, for example enhanced reporting, the mandating of independent decision making, an oversight role for the Independent Stakeholder Group or alignment with existing funding provided by other TO's. We would welcome further controls and discussion with Ofgem to ensure that we are able to continue to deliver value to our communities through the Net Zero Fund.

As the Draft Determination reallocates funding from this allowance we suggest that the same grant funding parameters are allowed for both mechanisms and that the Net Zero Fund be allowed to directly fund community projects.

We agree with Ofgem's proposal to retain the Net Zero Fund UIOLI and ask Ofgem to amend the parameters of the fund to include project funding, given the evidence and commentary within our DD response. In summary, through delivery experience we know that funding support is required to demonstrate measurable outcomes. Capacity building alone will not deliver a measurable social return on investment and ensure a just transition, especially to those groups who are vulnerable. Our inability to deliver measurable community outcomes would not only prevent us from meeting Ofgem's requirement to report a Social Return on Investment value but also result in the loss of tangible benefits for our vulnerable communities.

Chapter 16 - NARM

16.1 Overview

16.1.1 We are supportive of the use of the Network Asset Risk Metric (NARM) to measure Network Risk Benefit associated with our programme of asset interventions. The recent publication of Ofgem's decision on NARM Handbook Updates: threshold for justifying Clearly Identifiable Over or Under Delivery and related amendments[294] brought greater clarity to what delivery elements may be considered Clearly Identifiable Over or Under Delivery (CIOD/CIUD) at closeout of a price control period. While the clarity brought by the decision was required, it has confirmed a shortcoming of the current NARM Funding Adjustment and Penalty Mechanism ("the NARM Mechanism"). The poor correlation between baseline funding and network risk outputs, as identified by Ofgem in paragraph 3.5 of their consultation[295], will result in almost all our projects which have an outturn network risk which varies from the Baseline Network Risk Output (BNRO) being considered for bespoke ex-ante funding adjustment at closeout. We believe that this ex-post cost assessment and funding uncertainty is not conducive to enabling companies to make timely asset management decisions in the consumers' interest. We discuss this point further in our response to question OVQ5. Ahead of FD we require Ofgem to continue to work with companies to introduce further details around how certainty on funding adjustments can be achieved within a price control period.

16.1.2 We welcome the intent to improve the NARM framework set out in the Draft Determination. We are supportive of work which will enhance consistency and transparency. We provide further detail on our views regarding the alignment and expansion of NARM in our response to question OVQ6. We believe there is an opportunity to align methodologies across the electricity sector which Ofgem should look to promote in its regulatory direction. Given previous experience we are concerned at the potential increase in NARM asset scope. We therefore require Ofgem to engage with licensees ahead of the FD to define the list of assets to be included within the NARM framework such that an industry-consulted Electricity Transmission Common Methodology can be developed and presented for regulatory approval by 1st April 2027.

16.1.3 Two projects which were presented within the BNRO for RIIO-T3 have been identified as "Removed due to disallowed volumes" by Ofgem in the Draft Determination. We require Ofgem to engage with us ahead of the FD to agree the correct treatment of these projects. In addition to these two projects an error by Ofgem, resulting in the omission of BNRO associated with the asset types 132 OHL Conductor and 132kV OHL Fittings in table 6 of the electricity transmission annex, requires to be corrected for FD. We discuss these points more specifically within our response to OVQ4.

[294] https://www.ofgem.gov.uk/decision/narm-handbook-updates-threshold-justifying-clearly-identifiable-over-or-under-delivery-and-related-amendments
[295] https://www.ofgem.gov.uk/sites/default/files/2024-07/Consultation_on_threshold_for_justifying_Clearly_Identifiable_Over_or_Under_Delivery_under_the_NARM_Funding_Adjustment_and_Penalty_Mechanism.pdf

NARM QUESTIONS

OVQ 4 Do you agree with our proposed approach to measuring Baseline Network Risk Outputs and our application of the NARM mechanism?
We welcome the continued use of Long-Term Risk Benefit (LTRB) as the mechanism to measure the benefit delivered by NARM asset interventions. We will continue to work with Ofgem and other TOs to ensure that the currently approved method for the calculation of LTRB remains appropriate as we progress with NARM developments towards RIIO-T4.

We have seen a reduction of **R£14,394.2m** in Table 3 of the Overview Document. This reduction is categorised as "Removed due to disallowed volumes". We believe this categorisation is incorrect as no volumes have been disallowed by Ofgem. Our analysis identified that as well as the reduction associated with two projects due to their funding treatment, an error has been made in the calculation of the DD proposal value of R£8,707.5m by Ofgem.

Ofgem confirmed in its response to DDQ SPEN34 that the two schemes removed were SPNLT20138 ZP Route 400kV Minor Refurbishment and SPNLT20109 Glenlee to Tongland Modernisation. We discuss the treatment of these projects later in our response to this question.

BNRO Error
Our analysis of Table 6 in the SPT Annex also identified that a reduction in the following asset categories had been made:

Table 14-1 - SPT NARM BNRO Reduction Errors

NARM Asset Category	Reduction (R£m)
132kV OHL Conductor	775.06
132kV OHL Fittings	972.47

Ofgem confirmed in its response to DDQ SPEN34 that the LTRB associated with some interventions had not been picked up correctly in its modelling. Ofgem has confirmed that the correct total, with the two projects excluded, should have been R£10,455.00m as per **Error! Reference source not found.** We request this error be corrected by Ofgem at FD.

Table 14-2 - Corrected SPT BNRO with 2 Projects Removed

Asset Category	SPT Corrected BNRO (R£m)
132kV Circuit Breaker	19.37
132kV Transformer	622.54
132kV Reactor	0.00
132kV Underground Cable	1861.12
132kV OHL Conductor	775.06
132kV OHL Fittings	972.47
132kV OHL Tower	3108.81
275kV Circuit Breaker	114.39
275kV Transformer	418.72
275kV Reactor	0.00
275kV Underground Cable	0.00
275kV OHL Conductor	526.08
275kV OHL Fittings	0.00
275kV OHL Tower	1344.13
400kV Circuit Breaker	37.98
400kV Transformer	98.37

400kV Reactor	0.00
400kV Underground Cable	0.00
400kV OHL Conductor	0.00
400kV OHL Fittings	0.00
400kV OHL Tower	555.96
Total	**10455.00**

SPNLT20138 ZP Route 400kV Minor Refurbishment
The refurbishment of ZP route is a project which was anticipated to span price controls. This spanning of price controls was anticipated due to outages and deliverability constraints when submitting our RIIO-T2 Business Plan. To allow for the division of the project between regulatory price controls the delivery was split such that two regulatory projects were raised, one per circuit. The delivery of circuit number one on the route was raised as SPNLT203 in RIIO-T2 with a delivery date of 2026 while the other circuit was captured in SPNLT20138 which was forecast to deliver in RIIO-T3. At the time of RIIO-T3 Business Plan submission, the delivery profile for SPNLT20138 had materialised such that the expenditure for the project will be in RIIO-T2, as allowed for in the RIIO-T2 project assessment, while the commissioning of regulatory volumes will fall into RIIO-T3. Given the expected delivery of asset replacement volumes and associated LTRB within RIIO-T3 we had included the output of SPNLT20138 within our RIIO-T3 BNRO. After the submission of our RIIO-T3 Business Plan it has been possible to advance the delivery of SPNLT20138 when suitable outage window and contractor availability were aligned. It has therefore been possible to complete delivery of project SPNLT20138 within the RIIO-T2 period. We therefore now support the removal of the project from the RIIO-T3 BNRO and the outputs will instead be reported as A2 Funding Under a Separate Mechanism in RIIO-T2.

SPNLT20109 Glenlee to Tongland Modernisation
Scheme SPNLT20109 “Glenlee to Tongland Modernisation” was originally proposed as part of the RIIO-T2 BNRO. An extended planning process, and a public inquiry, meant that it became evident soon after RIIO-T2 business plan submission that it would not be possible to deliver the intervention in the RIIO-T2 period. The delay to the delivery of this project was communicated to Ofgem through the our Cost and Volumes (C&V) RRP commentary as well as the SPT NARM RRP from the earliest opportunity. The requirement for the public inquiry was communicated in C&V RRP 2022 with the resulting delay to project delivery detailed in C&V RRP 2023. The NARM impact of the project delay was first communicated in NARM RRP 2023 following confirmation of the project delay outwith our control. The requirement to deliver the intervention remains and has now been forecast to complete within RIIO-T3 following the resolution of the planning process. Expenditure has been forecast in the RIIO-T3 Business Plan related to the new delivery timeline for this work. And there has been expenditure on works related to the project in RIIO-T2. The BNRO has been reassessed and aligned with the forecast delivery of intervention volumes.

We note that within the RIIO-T3 DD that the RIIO-T3 funding associated with this project has not been awarded. This follows the approach taken for schemes which commence in RIIO-T2 and are to be dealt with as part of the RIIO-T2 close out process. It is our understanding, based on the definition of the NARM Funding Adjustment and Penalty Mechanism (RIIO-T2 SPT Special Licence Condition 3.1), that under delivery of LTRB for a project in the BNRO would result in recovery of allowance as part of the RIIO-T2 close out process. As we believe this project should be categorised as CIUD in RIIO-T2 it is not yet clear the value of the allowance that will be recovered as this will be determined as part of the close out process. Regarding the funding of costs incurred in RIIO-T2 we have requested clarity, through DDQ SPEN53, on whether the assurances made in paragraph 4.131 of the Electricity Transmission DD document apply to the NARM funding mechanism, specifically regarding the funding of efficient and justified investment ahead of output. We require that the treatment of RIIO-T2 expenditure associated with NARM projects delivering into RIIO-T3 is defined in greater detail.

Paragraph 4.131 of the Electricity Transmission document provides some comfort in the recovery of RIIO-T2 expenditure associated with projects which have justified delays into early RIIO-T3. Ofgem confirmed in its response to DDQ SPEN53 that, subject to further project specific information being provided, that it is broadly the intention that NARM projects would receive this treatment. While this paragraph provides some clarity on RIIO-T2 it does not address the requirement for RIIO-T3 funding to

complete the project. The latest version of the NARM Handbook[296] in Paragraph 8.3 states that "For some, or all, of the Over-Delivery and Under-Delivery to be considered justified, the licensee is required to satisfactorily complete all of the following requirements as part of its NARM Closeout Report." Condition 8.3.b sets out that such a Closeout Report must "provide a detailed explanation of why the factors driving Over-Delivery or Under-Delivery could not reasonably have been forecast as part of the price control setting process and factored into the licensee's final NARM Workbook." Given that the delay to the delivery of the project was signalled, and a new delivery timeline proposed, ahead of the RIIO-T3 Business Plan submission we do not consider this would meet the criteria of "could not reasonably been forecast" and therefore leave the scheme ineligible for NARM funding in RIIO-T3. With no clarity on the mechanisms or considerations that will be made as part of allowance adjustment during the RIIO-T2 close out process for projects that span price controls we believe that funding and LTRB associated with this project has been wrongly withheld from the RIIO-T3 BNRO. For projects which span price controls we request Ofgem provide further detail on how funding will be treated in each of the relevant price control periods. Companies require certainty on the continued funding of works which are currently in delivery, and which will deliver value for consumers. We request that Ofgem detail in their FD how the NARM mechanism will move away from ex-post allowance assessment following consultation with network companies. We require Ofgem to specifically identify how SPNLT20109 "Glenlee to Tongland Modernisation" will be funded.

OVQ 5 Do you agree with our proposed approaches to calculating the funding adjustments and to the application of penalties?

We are generally supportive of the approach to the NARM Mechanism. However, the NARM Mechanism, while incentivising delivery of the BNRO, does not provide suitable longer term clarity for us when our NARM programme must adapt to emergent issues and a continually changing delivery landscape.

We have on previous occasions, including in our response[297] to the Statutory Consultation on issuing updates to the Network Asset Risk Metric Handbook, expressed our concerns about funding uncertainty related to the NARM mechanism. This principally arises due to the significant number of projects we believe meet the criteria for, and would be classified as, CIOD or CIUD based on their outturn Unit Cost of Risk (UCR) relative to the baseline UCR. This treatment of projects, while reducing exposure to allowance adjustment which would be non-representative of expenditure to the detriment of consumers or companies, leaves significant uncertainty for companies because of ex-post allowance adjustment. Several discussions have been had in NARM working groups both for electricity transmission as well as cross sector incorporating gas transmission and gas distribution network owners. The variation in volume and nature of projects across sectors means that it's unlikely that one single solution can be implemented to resolve all the challenges faced by licensees with the current NARM mechanism. However, the uncertainty over funding adjustment under the NARM mechanism is not conducive to promoting timely asset management decisions.

We would again reiterate our previous requests to see greater transparency on the funding assessment and approval of justification case in period, providing certainty to companies allowing delivery to be committed to at pace. We believe there is a place for mechanistic adjustment of allowance, however this is likely to be through the correlation of allowance and asset volumes where delivery volumes are varied. There is precedent within the load related project area for mechanisms which allow for an automatic mechanism to adjust allowance, either the Generation Connections volume driver or Demand Connections volume driver, being supplemented with a reopener mechanism, namely the Medium Sized Investment Projects (MSIP) re-opener in RIIO-T2. The DD proposal to continue this composite approach, albeit under a revised framework, is one which we believe could work in the NARM environment. A mechanism which adjusts project allowance based on volume (or risk in the case of a single asset) delivered would allow companies to have certainty around project funding without unnecessarily increasing regulatory burden. A combination of reopeners with reporting requirements which are reflective of their allowance threshold and/or a Use It Or Lose It allowance would provide the necessary regulatory framework for decisions to be made at pace, companies to be funded to deliver necessary works and consumer interests to be protected. All interventions would be reported through the rigours of NARM RRP to ensure transparency. We believe that the Portfolio Engineering Justification Papers

[296] https://www.ofgem.gov.uk/sites/default/files/2025-06/NARM-Handbook-v4.0.pdf
[297] https://www.ofgem.gov.uk/sites/default/files/2025-06/SPT_Response_Statutory%20Consultation%20on%20Network%20Asset%20Risk%20Metric%20handbook%20clearly%20identifiable%20threshold-20250627112340.pdf

(EJPs) established as part of the RIIO-T3 Business Plan process establish an effective baseline against which interventions can be tracked.

We require Ofgem to address the concerns of licensees by enhancing the NARM mechanism ahead of FD and introduce the necessary change to bring such changes into place ahead of RIIO-T3.
For clarity, we believe that projects which contain NARM assets should be dealt with through the NARM mechanism. For non-load related interventions which do not include NARM assets we provide narrative around these in our response to the Non-Load Reopener, questions ETQ44 and ETQ45.

The application of a penalty for unjustified under delivery serves to promote delivery of network risk improvement and we look forward to continuing open dialogue with Ofgem to ensure that changes to our delivery plan, should they occur, are clearly justified and fully understood.

OVQ 6 Do you agree with our proposed approaches to improving the NARM framework?
We are supportive of the objectives of alignment of the NARM methodology in the ET sector and the activities proposed to promote transparency and consistency. While alignment within the ET sector is the primary concern, the NARM objectives, as set out in SPT Special Licence Condition 9.2 of the RIIO-T2 licence, also place an obligation on licensees to enable comparative analysis between the Transmission Systems and Distribution Systems within Great Britain. Licence drafting for RIIO-T3 proposes to retain this requirement. This means that as well as increasing alignment in the electricity transmission sector it is also prudent to consider how better alignment may be achieved with the NARM methodology in place in the electricity distribution sector at this time. To promote greater alignment within the energy sector we believe that Ofgem should present a clear vision on the future of NARM to facilitate coordinated development. This vision should be presented in working groups with clear actions points and incorporated into the drafting of the FD. An example of this is whether Ofgem considers that the use of the same calculation approach for probability of failure being used in the electricity sector is preferable for alignment of the regulatory framework. We are of the view that it would be prudent for TOs and DNOs to align the NARM calculations at electricity transmission with those in use at electricity distribution as far as reasonably practical. While we remain firm that NARM should not be used to dictate the asset management practices of a licensee, we recognise that use of a common regulatory reporting metric for asset risk provides a means by which risk values can be universally understood and compared across the industry, such are the objective of NARM.

While we are supportive of the developments proposed in the ET sector, we have concerns about the scope of alignment and expansion activities which are expected to conclude in a comparatively short period, given experience from previous work in this area. The Sector Specific Methodology Decision[298] set out improvements for NARM including “covering more assets” (Overview document, paragraph 6.85). Subsequently an extensive list of prospective assets for NARM expansion has been presented by Ofgem and discussed in the Electricity Transmission working groups. The initial drafting of RIIO-3 licence condition Electricity Transmission Special Condition 9.3[299] refers to licensees working with other TOs to develop a “common list of assets to be used in the Electricity Transmission Common Methodology”. We consider the origin of this list of potential future NARM assets to be inconsistent between the policy and the licence draft. The lack of definition in the DD leaves the requirement for this additional asset modelling open to interpretation, both in scope and origin. The list of assets that will be acceptable for “regulatory approval” on 1st April 2027 will have an impact on the work required by TOs to develop suitable models and system.

While we have already taken steps to model additional asset categories internally, ensuring alignment of this modelling in a consistent manner with other TOs will require time and effort. Some asset categories lend themselves well to the expansion of our current risk modelling approach, while others, such as civils and HVDC, are both complex and likely to require bespoke adjustments to the current framework. These adjustments, while possible, pose a challenge in the achievements of the objectives set out when the relatively short development and delivery period is considered. To support the timely development of the Electricity Transmission Common Methodology, we require Ofgem to engage with TOs on the definition of this scope expansion ahead of FD.

[298] https://www.ofgem.gov.uk/decision/riio-3-sector-specific-methodology-decision-gas-distribution-gas-transmission-and-electricity-transmission-sectors
[299] https://www.ofgem.gov.uk/consultation/riio-3-initial-licence-consultation

We also note that reference was made in the SSMD to “Enhancing assurance” for NARM including (Overview document, paragraph 6.101 & 6.102). This decision set out what we believe to have been Ofgem’s intent to implement an audit and report regime on the data within the NARM methodology. The SSMD requirement detailed a need for the appointment of external auditors to carry out both site-based and office-based reviews of the accuracy, completeness and timeliness of NARM data across TOs. We have not identified any detail having been provided in the DD of Licence Drafting for this policy decision. We require Ofgem to either engage with network companies ahead of FD on the scope and mechanism by which this should be achieved or acknowledge that the policy decision has been revised and will no longer be
enforced.

Chapter 17 - Data and Digitalisation

17.1 Overview

17.1.1 We are pleased to see that Ofgem has recognised the need and scale of challenge in delivering the data and digitalisation investments required to support the evolving needs of the energy sector with the overall 98% award of the funding requested.

17.1.2 This will allow us to continue our journey of creating an organisational culture where data is treated as a valuable asset. We will enhance our capabilities to maximise the value from data and build the trust to securely share our data with our customers and stakeholders, thereby enhancing our maturity against the 11 Data Best Practice principles.

17.1.3 We agree that the CRM Enhancements initiative within the CRM Optimisation EJP, which was not awarded the requested investment figure of £1.7m, lacked clarity on the specific delivery scope. We have improved this EJP to now detail the specific deliverables across the RIIO-T3 period, which also now have measurable/time-bound goals associated to them, as well as the benefits of these changes to our customers & stakeholders. Making the digital changes detailed in this revised EJP are critical to delivering the wider scope/goals of Connections Reform and ensuring the CRM platform is robust, scalable and integrated with key systems to drive process efficiency and customer satisfaction.

17.1.4 We have submitted Annex 5.16 which is our revised **Engineering Justification Paper RIIO-T3-D&D-EJP02**: CRM Optimisation alongside our consultation response.

DATA and DIGITALISATION QUESTIONS

OVQ 36 Do you agree with our position of not changing the Digitalisation licence condition?
SPEN are comfortable with the proposal to keep the Digitalisation licence condition unchanged.
We seek clarity from Ofgem on the difference between a required Digital Strategy Update (every 2 years) and Action Plan Update (every 6 months) as these are often referred to as a single entity however have different purposes and not all DSAP guidance and principles apply to both.
Furthermore, as SPEN have both a distribution and transmission licence which has the same DSAP licence applicable to both, we would like to highlight the potential differing path being discussed as part of the early RIIO-ED3 data & digitalisation working groups. In RIIO-ED3 the initial Ofgem proposal included aligning to specific strategic outcomes and agreed KPIs which would be reported via the 6 monthly action plans. It was suggested that the DSAP guidance would be updated to reflect this for RIIO-ED3 so there is a potential for there to now be two different versions of DSAP guidance going forward.
SPEN's position is that the DSAP licence condition should be the same for both distribution and transmission licences. As the RIIO-T3 licence drafting will be before the RIIO-ED3 licence drafting we believe that any changes should be made for RIIO-T3 and then reflected in RIIO-ED3 otherwise there will be several years where these licence conditions will not be the same.

OVQ 37 Do you agree with our proposed approach to the DSI licence condition?
SPEN agree the need for a licence condition to support development – deployment of Data Preparation Node and participation in the Trust Framework – and on-going operation of the DSI. SPEN considers the licence must be written to allow sufficient time for network operators to develop the data and any requisite integrations for each use-case; and, we ask the licence draft has clear considerations with respect to delivery timescales.

Furthermore, to allow a fair measure of compliance with the licence, the condition must recognise the mandates from the DSI governance arrangements. With regard to continued support of the platform operation within SPEN and agreed data products, SPEN supports enforcement of the licence condition based on data contracts (i.e. data product specification, which includes requirements and guarantees including data quality), SPEN considers the DSI governance the best forum to agree these data contracts. An additional consideration is that SPEN will be reliant on the DSI Coordinator to ensure the DSI components are fully functional and supported, allowing SPEN to develop and maintain their DSI components – we ask this is recognised in the licence condition.

We look forward to reviewing the draft licence condition in due course to ensure it reflects DD intention.

OVQ 38 Do you agree with our proposed design of the Digitalisation re-opener?
SPEN understand the drive to make any re-opener criteria common and consistent across all/TOs however we do feel that this may result in reduced flexibility and ability to deliver additional value identified during the price control period if the proposed deliverable does not meet this small list of acceptable criteria. This prescriptive approach contradicts the accepted view that the digital technology landscape is fast moving so TOs need a more flexible mechanism to prevent falling behind. SPEN ask that Ofgem takes this factor into consideration to ensure the re-opener criteria is flexible enough and not restrictive to adopting wider innovation at pace.
Under the proposed criteria it seems that Ofgem has included the following item 3 to try and give flexibility for TOs to take advantage of emerging technologies however the definition of Mature Innovation is also restrictive:

- the licensee implementing Mature Innovation** related to data and Digitalisation to fulfil obligations in the conditions of this licence

**'Mature Innovation' in relation to the Digitalisation Re-opener means a product or service that has:
(a) progressed through network innovation spending, such as the SIF, NIC, or NIA, to the point where it is ready to be considered as part of business-as-usual operations;
(b) is the result of industry-wide activities relating to the modernisation of regulatory reporting; or
(c) is the result of industry-wide activities relating to the implementation of the Technology Business Management taxonomy.

It is common for new products or features to be made available in the wider technology market in a short space of time however these would not meet the above definition as they won't have been a SIF, NIC or NIA innovation project led by TOs. For example, generative AI and the benefit of being able to adopt this within the energy sector was not as a result of an industry innovation project. This new technology emerged very quickly and under the proposed re-opener criteria, SPEN would not be able to take advantage of this until the next price control period.
In addition, throughout the price control period evolving business risks and stakeholder priorities can emerge and the solution could be a non-innovative technology however we did not get awarded funding to deliver this, and it would not fall under the re-opener category.
SPEN would recommend that the same digitalisation re-opener guidance and criteria currently in place for RIIO-T2 remains in place for RIIO-T3.

SPTQ 10 Do you agree with our proposed level of funding for SPT's data and digitalisation investments?
SPEN are pleased with the overall 98% award of the total data & digitalisation funding requested.
We agree that the initiative within the CRM Enhancements EJP, which was not awarded the requested investment figure of £1.7m, lacked clarity on the specific delivery scope. We have improved this EJP to now detail the specific deliverables across the RIIO-T3 period, which also now have measurable/time-bound goals associated to them, as well as the benefits of these changes to our customers & stakeholders. Making the digital changes detailed in this revised EJP are critical to delivering the wider scope/goals of Connections Reform and ensuring the CRM platform is robust, scalable and integrated with key systems to drive process efficiency and customer satisfaction.
We have submitted revised Engineering Justification Paper **RIIO-T3-D&D-EJP02: CRM Enhancements** alongside our consultation response.

ETQ 40 Do you have any views with our proposed approach to ITA project eligibility?
We welcome Ofgem's position that the ITA will be applied to only a small subset of CSNP projects and the wider project eligibility now proposed. However, the lack of clarity of eligibility criteria at this stage, when non-CSNP projects will be 'live' from day one of RIIO-T3 is a concerning lack of progress and transparency. We would ask Ofgem to confirm projects which maybe being considered. Whilst we recognise the proposed consultation on ITA eligibility considerations as part of the ITA Governance Document consultation following FD, aligns with the expectation that CSNP methodology will be clearer at this time, this does not consider the potential wider application of an ITA to non CSNP projects.
Given that the application of ITA to only a subset of CSNP projects is thought to be proportionate (with which we agree), it is illogical to include lower materiality projects and an absolute necessity to consider the complexity of a project when considering ITA application. Projects which maybe large in value or scope, could be straightforward in delivery, whilst others maybe small and very complicated and therefore

benefit from having an ITA. Although we would strongly advocate that an ITA could add most value in a high value, high risk projects with considerable consumer benefit, recognising that amount of consumer benefit does not feature in the Ofgem current assessment criteria. Given this position we welcome the extension of considering ITA application to beyond CSNP-F projects, however along with a clear governance document believe an ITA appointment should be timely and appropriate within a project to support and aid delivery of a project rather than cause unnecessary stalling for review and potential delay.
The logic behind the eligibility criteria in table 7 is unclear, we would expect similar application and consideration between tCSNP2 and CSNP outputs given their assessment by the NESO. There is an expectation that project eligibility characteristics should be streamlined across all types of eligible projects for consistency and to maximise the application of the ITA.
As Ofgem continues to develop the framework for the ITA, in collaboration with TOs and wider industry, we are keen to be engaged in this process to maximise the consumer benefit an ITA appointment could make and ensure TOs have clear criteria to follow.

ETQ 41 Do you have any views on the appropriate information sharing boundaries between the TO and an ITA, and how any conflicts could be managed?
It is difficult to comment at this point because of the paucity of information from Ofgem on the scope of the ITA for any considered project. However, it could be anticipated that full project documentation including pre-assessments, designs, specifications, contract and commercial terms would need to be shared to fulfil the ITA's objectives. This is a clear risk with respect to commercial confidentiality and intellectual property rights and we firmly support the governance approach detailed in the DD chapters 4.145-4.147. Compliance with any data sharing restrictions and confidentiality agreements are critical to ensure that not only is TO commercial information is secure but perhaps more importantly details of projects critical for national infrastructure and system security. We have consistently advocated for the need of a secure data room, from which documentation cannot leave to mitigate some of this risk and the need for internally ringfenced personnel to secure sensitive information.
There are wider issues which must be considered, we require that Ofgem considers: the way in which any conflict between an ITA and TO should be managed; provide clear guidelines for TOs in how we support an ITA in making recommendations to Ofgem; and set out how Ofgem will use, assess and apply information from the ITA when making decisions in relation to a TO project, all whilst maintaining the necessary pace of project delivery and providing clear and comprehensive reasons for its decisions. Without clarity on these aspects of involvement and decision making, there is the potential that ITA involvement diminish the effect and capabilities of an experienced and effective TO, whilst also increasing the regulatory burden, and negatively impacting the quality of Ofgem decision making.
We request Ofgem to publish the planned associated document (ITA Governance Document) and recognise the impact we can make by responding to the consultation on the governance and operational processes.

Chapter 18 - Climate Resilience

18.1 Overview

18.1.1 We note and are supportive of Ofgem's review of climate resilience. We acknowledge that the proposals for ongoing development and implementation remain consistent with the SSMD and are fully committed to and engaged in the process.

CLIMATE REILIENCE QUESTIONS

OVQ 8 Do you agree with our approach taken to review of the Climate Resilience strategies?
We are supportive of Ofgem's approach to Climate Resilience and the feedback contained in the Draft Determination. We look forward to working with Ofgem and other Stakeholders in the next steps in implementing our Climate Resilience Strategy and the further consultation on Ofgem additional guidance being developed during RIIO-T3.

Annex 1
Mapping to Ofgem's Questions

OFGEM DOCUMENTS	SPT SUBMISSION	
RIIO-3 DD - Overview	Chapter	Page Number
OVQ 1. We would welcome any views on the enduring role of the ISGs during RIIO-3 and for future price controls.	Chapter 11 - Stakeholder Engagement	178
OVQ 2. Do you agree with our proposed position on the Environmental Action Plan and Annual Environmental Report ODI-R for RIIO-3?	Chapter 14 - Environmental Sustainability	198
OVQ 3. Do you agree with our consultation position to create a new common mechanistic PCD for ZEV and associated infrastructure costs?	Chapter 14 - Environmental Sustainability	198
OVQ 4. Do you agree with our proposed approach to measuring Baseline Network Risk Outputs and our application of the NARM mechanism?	Chapter 16 - NARM	215
OVQ 5. Do you agree with our proposed approaches to calculating the funding adjustments and to the application of penalties?	Chapter 16 - NARM	217
OVQ 6. Do you agree with our proposed approaches to improving the NARM framework?	Chapter 16 - NARM	218
OVQ 7. Do you agree with our proposal for the physical security PCD?	Chapter 3 - Cost Assessment – Key Totex	100
OVQ 8. Do you agree with our approach taken to review of the Climate Resilience strategies?	**Chapter 18 - Climate Resilience**	223
OVQ 9. Do you agree with our views on the Workforce Resilience Strategies?	Chapter 13 - Workforce and Supply Chain	190
OVQ 10. Do you agree with our views on the Supply Chain Resilience Strategies?	Chapter 13 - Workforce and Supply Chain	190
OVQ 11. Do you agree with the equal weightings applied per criteria/rating for the 'Clarity scorecard' and the 'Business Plan Commitments scorecard' for the Stage C assessment?	Chapter 10 - Business Plan Incentive	169
OVQ 12. Do you agree with the weightings applied per outcome for each sector for use in the Stage C - Business Plan commitments assessment?	Chapter 10 - Business Plan Incentive	169
OVQ 13. Do you agree with the use of a default materiality threshold and its level?	Chapter 10 - Business Plan Incentive	169
OVQ 14. Do you agree with out proposed amendments to the CAM for RIIO-3?	Chapter 12 - Innovation	180

OVQ 15. Do you agree with our proposed design of the NZARD UIOLI?	No Response (Gas Sector)	
OVQ 16. Do you agree with our proposed design of the NZASP re-opener?	No Response (Gas Sector)	
OVQ 17. Do you agree with our design proposal for the resilience re-opener?	Chapter 3 - Cost Assessment – Key Totex	100
OVQ 18. Do you agree with our proposed approach to RPEs?	Chapter 8 - Real Price Effects	163
OVQ 19. Do you agree with our proposed approach to ongoing efficiency?	Chapter 9 - Ongoing Efficiency	167
OVQ 20. Do you agree with our proposed NIA funding levels?	Chapter 12 - Innovation	180
OVQ 21. Do you agree with our approach to the future of gas-related workstreams?	No Response (Gas Sector)	
OVQ 22. Do you agree that £2.5m of additional NIA should be used to provide enhanced advisory services for innovators at the early stages of innovation development?	Chapter 12 - Innovation	180
OVQ 23. Do you agree with our approach to improving oversight and reporting of the NIA?	Chapter 12 - Innovation	181
OVQ 24. Do you agree with our proposals to allocate £500m for SIF funding?	Chapter 12 - Innovation	181
OVQ 25. Do you agree with our proposals to introduce a 'Programmatic Approach' to the SIF?	Chapter 12 - Innovation	181
OVQ 26. Do you agree with our proposal to introduce a £50m deployment fund, utilising £50m from the total £500m SIF allocation?	Chapter 12 - Innovation	181
OVQ 27. Do you agree that the deployment fund should also be open to innovation projects that haven't been funded through NIA, NIC or SIF?	Chapter 12 - Innovation	182
OVQ 28. Do you agree with our proposal to reverse the SSMD position of removing the Discovery phase from SIF?	Chapter 12 - Innovation	182

OVQ 29. Do you agree with our proposals to retain the core aspects of the SIF for RIIO-3?	Chapter 12 - Innovation	182
OVQ 30. Do you agree with our proposals for a more flexible approach to contribution rates to fund SIF projects?	Chapter 12 - Innovation	182
OVQ 31. Do you agree with updating the SIF eligibility criteria and assessment process?	Chapter 12 - Innovation	182
OVQ 32. Do you agree with our proposal to establish a direct pathway for transformative projects to seek Ofgem's support for funding?	Chapter 12 - Innovation	182
OVQ 33. Do you agree on the need to clarify roles and responsibilities within the innovation ecosystem, and the factors that we should consider?	Chapter 12 - Innovation	182
OVQ 34. Do you agree with our approach to improving reporting of deployed SIF projects and lessons learned post-funding?	Chapter 12 - Innovation	183
OVQ 35. Do you agree with our proposals for the Cyber Resilience re-opener?	See Confidential Cyber Response (TBC)	
OVQ 36. Do you agree with our position of not changing the Digitalisation licence condition?	Chapter 17 - Data and Digitalisation	220
OVQ 37. Do you agree with our proposed approach to the DSI licence condition?	Chapter 17 - Data and Digitalisation	220
OVQ 38. Do you agree with our proposed design of the Digitalisation re-opener?	Chapter 17 - Data and Digitalisation	221

RIIO-3 DD – ET Annex	*Mapping to Chapter*	**Mapping to Page Number**
ETQ 1. 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?	Chapter 5 - Incentives	124
ETQ 2. Do you agree with our proposed approaches to determining a TDD for CSNP-F Outputs and non-CSNP-F Outputs?	Chapter 5 - Incentives	125
ETQ 3. Do you agree with our proposed inclusion of a minimum availability standard in the CSNP-F ODI-F?	Chapter 5 - Incentives	126
ETQ 4. Do you agree with our proposed approach to Delay Events in the CSNP-F ODI-F?	Chapter 5 - Incentives	126

ETQ 5. Do you agree with our proposed shape and size of the CSNP-F ODI-F incentive?	Chapter 5 - Incentives	126
ETQ 6. Which of the two proposals for the Connections Capacity ODI-F target setting methodology do you think is most appropriate and why?	Chapter 5 - Incentives	127
ETQ 7. 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?	Chapter 5 - Incentives	130
ETQ 8. Do you agree with our proposed design of the Community Benefit Funding pass-through mechanism?	Chapter 15 - Community Benefits and Net Zero Fund	208
ETQ 9. What are your views on our consultation positions for the TOs' EAP commitments in RIIO-ET3?	Chapter 14 - Environmental Sustainability	199
ETQ 10. 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?	Chapter 5 - Incentives	130
ETQ 11. 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?	Chapter 14 - Environmental Sustainability	200
ETQ 12. 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?	Chapter 5 - Incentives	130
ETQ 13. Do you consider that we should use the IIG Exceptional Event mechanism to manage potential issues with historical IIG inventory data? If so, why?	Chapter 5 - Incentives	130
ETQ 14. What are your views on our consultation position for the SF6 Asset Intervention PCD in RIIO-ET3?	Chapter 5 - Incentives	132
ETQ 15. What are your views on our proposals for the RIIO-ET3 ENS ODI-F, including the two different target setting methodologies we have shared?	Chapter 5 - Incentives	132
ETQ 16. What are your views on our consultation position for the SO:TO incentive approach to BAU enhanced services in ET3?	Chapter 5 - Incentives	132
ETQ 17. Do you agree with our proposal to introduce a clawback mechanism in the SO:TO ODI-F for enhanced services requested that are unfulfilled?	Chapter 5 - Incentives	133
ETQ 18. Which of the three options for managing differing approaches between TOs do you think would work most effectively in the SO:TO ODI-F?	Chapter 5 - Incentives	133
ETQ 19. 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?	Chapter 5 - Incentives	133

ETQ 20. What are your views on our proposed design of the Innovative Delivery Incentive?	Chapter 5 - Incentives	134
ETQ 21. What are your views on how TOs could demonstrate 'consumer value' to justify rewards under the Innovative Delivery Incentive?	Chapter 7 - Value for Money	158
ETQ 22. Do you agree with our proposal to introduce the CSNP Co-ordination LO?	Chapter 6 - Growth Mechanisms	142
ETQ 23. What are your views on our consultation position for the LEI UIOLI in RIIOET3?	Chapter 14 - Environmental Sustainability	202
ETQ 24. 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?	Chapter 11 - Stakeholder Engagement	178
ETQ 25. Do you agree with our proposal to retain the APM for RIIO-ET3 in its current form?	Chapter 13 - Workforce and Supply Chain	190
ETQ 26. Do you agree with our intended approach to PCF in RIIO-ET3?	Chapter 6 - Growth Mechanisms	143
ETQ 27. Do you agree with our updated definition of EEW?	Chapter 6 - Growth Mechanisms	146
ETQ 28. Do you agree with our proposed approach to PCF on tCSNP2 projects?	Chapter 6 - Growth Mechanisms	146
ETQ 29. Do you agree with our proposed scope, re-opener windows and materiality threshold for the Load Re-opener?	Chapter 6 - Growth Mechanisms	146
ETQ 30. Is it clear how the different Load Re-opener tracks operate, and do you agree with the rationale for introducing them?	Chapter 6 - Growth Mechanisms	147
ETQ 31. Do you agree with the scope and materiality threshold for the Load UIOLI?	Chapter 6 - Growth Mechanisms	149
ETQ 32. Do you agree with our proposed design of the generation and demand connections volume driver mechanisms?	Chapter 6 - Growth Mechanisms	150
ETQ 33. Do you agree with our proposal to apply the 'stepped TIM' to volume drivers as part of general totex?	Chapter 6 - Growth Mechanisms	151
ETQ 34. Do you agree with our proposed methodology for excluding atypical connection projects from the regression model?	Chapter 6 - Growth Mechanisms	151

ETQ 35. Do you agree with our proposal to use the Load Re-opener (above £25m) and Load UIOLI (below £25m) to fund projects that fall outside ±1.5 standard deviations from the regression model?	Chapter 6 - Growth Mechanisms	151
ETQ 36. Do you agree with our treatment of RIIO-ET3 Volume Driver crossover projects and our approach to allowance profiling?	Chapter 6 - Growth Mechanisms	152
ETQ 37. Do you agree with the proposed scope of the CSNP-F Re-opener?	Chapter 6 - Growth Mechanisms	152
ETQ 38. Do you have any views on our proposed design of the CSNP-F Re-opener?	Chapter 6 - Growth Mechanisms	152
ETQ 39. Do you agree with our proposed approach to T2/T3 crossover projects?	Chapter 6 - Growth Mechanisms	153
ETQ 40. Do you have any views with our proposed approach to ITA project eligibility?	Chapter 17 - Data and Digitalisation	221
ETQ 41. Do you have any views on the appropriate information sharing boundaries between the TO and an ITA, and how any conflicts could be managed?	Chapter 17 - Data and Digitalisation	222
ETQ 42. Do you agree with our proposed Carbon Compensation UIOLI to fund carbon offsetting in RIIO-ET3?	Chapter 14 - Environmental Sustainability	202
ETQ 43. Do you have any views on our proposal to reject these two environmental UMs?	Chapter 14 - Environmental Sustainability	202
ETQ 44. 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?	Chapter 6 - Growth Mechanisms	153
ETQ 45. Do you agree with our proposed design of the Non-Load Re-opener?	Chapter 6 - Growth Mechanisms	153
ETQ 46. 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?	Chapter 3 - Cost Assessment – Key Totex	100
ETQ 47. 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?	Chapter 3 - Cost Assessment – Key Totex	100
ETQ 48. Do you agree with our proposal to roll-up unit cost benchmarks and set the benchmarks at the scheme level?	Chapter 3 - Cost Assessment – Key Totex	101

ETQ 49. Do you agree with our continued use of the PAM? How can this be further improved?	Chapter 3 - Cost Assessment – Key Totex	101
ETQ 50. 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.	Chapter 3 - Cost Assessment – Key Totex	101
ETQ 51. 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?	Chapter 3 - Cost Assessment – Key Totex	103
ETQ 52. 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?	Chapter 4 - Cost Assessment – IT and Telecoms	113
ETQ 53. 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?	Chapter 3 - Cost Assessment – Key Totex	103
ETQ 54. 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?	Chapter 3 - Cost Assessment – Key Totex	104
ETQ 55. 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?	Chapter 3 - Cost Assessment – Key Totex	105
ETQ 56. 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?	Chapter 3 - Cost Assessment – Key Totex	106
ETQ 57. What are your views on the proposed blended approach to CAI? Do you agree with the weights applied?	Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)	84
ETQ 58. 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?	Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)	86
ETQ 59. Do you agree with our proposal to remove the opex escalator for RIIO-ET3?	Chapter 3 - Cost Assessment – Key Totex	106
ETQ 60. Do you agree with our approach to BSC? How do you think this could be improved?	Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)	87
ETQ 61. 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?	Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)	90

ETQ 62. Do you agree with our approach to MEAV? What do you think we could do to improve its robustness?	Chapter 2 - Cost Assessment – Indirect Costs (CAI & BSC)	91
ETQ 63. Do you agree with our approach to operational training? What else should be considered within this approach?	Chapter 13 - Workforce and Supply Chain	192
ETQ 64. Do you agree with our approach on insurance? What methodological improvements can we make?	Chapter 1 - Ensuring an investable finance package	55
ETQ 65. Do you agree with our approach to pension scheme admin and PPF levy? What else should be considered within this approach?	Chapter 1 - Ensuring an investable finance package	55
ETQ 66. Do you agree with our assessment approach for Physical Security? If not, how should we assess these costs?	Chapter 3 - Cost Assessment – Key Totex	106
ETQ 67. Do you have any views on our engineering assessment of the thematic issues we have identified?	Chapter 7 - Value for Money	160
ETQ 68. Do you agree with our approach to maintaining future optionality through ensuring licensees use extendible designs?	Chapter 7 - Value for Money	160
ETQ 69. 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?	Chapter 14 - Environmental Sustainability	207
ETQ 70. 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?	Chapter 5 - Incentives	135
ETQ 71. Do you agree with our proposed 'stepped' design of the RIIO-ET3 TIM, including the values that we have used to set each 'step'?	Chapter 5 - Incentives	135
ETQ 72. Do you agree with our proposal to include ASTI within this TIM approach?	Chapter 5 - Incentives	135

RIIO-3 DD – SPT Annex	Mapping to Chapter	**Mapping to Page Number**
SPTQ 1. Do you agree with our proposal to retain the Net Zero Fund UIOLI for SPT, and with our proposed parameters for it?	Chapter 15 - Community Benefits and Net Zero Fund	210
SPTQ 2. Do you agree with our proposal to introduce this PCD for SPT?	Chapter 3 - Cost Assessment – Key Totex	106
SPTQ 3. Do you agree with our view that SPT passed all of the minimum requirements and as such are considered to have passed Stage A of the BPI?	Chapter 10 - Business Plan Incentive	169

SPTQ 4. Do you agree with our assessment results for SPT against Stage B of the BPI?	Chapter 10 - Business Plan Incentive	169
SPTQ 5. Do you agree with our assessment results for SPT against Stage C of the BPI?	Chapter 10 - Business Plan Incentive	170
SPTQ 6. Do you agree with our proposed unit rates?	Chapter 3 - Cost Assessment – Key Totex	107
SPTQ 7. Do you agree with our proposal to reject SPT's Environmental Re-opener?	Chapter 14 - Environmental Sustainability	205
SPTQ 8. What are your views on our engineering assessment of SPT's RIIO-ET3 Business Plan?	Chapter 7 - Value for Money	160
SPTQ 9. Do you agree with the level of proposed NIA funding for SPT?	Chapter 12 - Innovation	183
SPTQ 10. Do you agree with our proposed level of funding for SPT's data and digitalisation investments?	Chapter 17 - Data and Digitalisation	221

RIIO-3 DD – Finance Annex	Mapping to Chapter	**Mapping to Page Number**
FQ 1. Do you agree with our approach to estimating efficient debt costs and calibrating the index?	Chapter 1 - Ensuring an investable finance package	40
FQ 2. Do you agree with our proposal to use a combination of iBoxx GBP A and BBB 10+ non-financial indices rather than the iBoxx GBP Utilities 10+?	Chapter 1 - Ensuring an investable finance package	40
FQ 3. Do you consider our proposed notional ILD assumption to be appropriate?	Chapter 1 - Ensuring an investable finance package	40
FQ 4. Do you agree with our approach to setting the additional cost of borrowing allowances?	Chapter 1 - Ensuring an investable finance package	40
FQ 5. Do you agree with our proposed treatment of inflation with respect to the allowed return of debt?	Chapter 1 - Ensuring an investable finance package	41
FQ 6. Do you agree with the removal of the infrequent issuer allowance?	Chapter 1 - Ensuring an investable finance package	44
FQ 7. Do you agree with our methodology for calculating the RFR?	Chapter 1 - Ensuring an investable finance package	44

FQ 8. Do you agree with our methodology for calculating the inflation wedge?	Chapter 1 - Ensuring an investable finance package	44
FQ 9. Do you agree with our methodology change in calculating the ex ante TMR?	Chapter 1 - Ensuring an investable finance package	45
FQ 10. Do you agree with our methodology for estimating beta?	Chapter 1 - Ensuring an investable finance package	45
FQ 11. Do you agree with our proposed set of comparators which also incorporates selected European utility stocks?	Chapter 1 - Ensuring an investable finance package	45
FQ 12. Do you agree with the conclusions we have drawn from our chosen crosschecks?	Chapter 1 - Ensuring an investable finance package	46
FQ 13. Do you agree with our treatment of risks to the ET and Gas sectors as nonsystematic?	Chapter 1 - Ensuring an investable finance package	46
FQ 14. Do you agree with our proposed dividend allowance policies for the notional gas and electricity companies?	Chapter 1 - Ensuring an investable finance package	47
FQ 15. Do you agree with our proposal not to apply the flat WACC approach?	Chapter 1 - Ensuring an investable finance package	47
FQ 16. Do you agree that our proposed package for gas and electricity companies is investable?	Chapter 1 - Ensuring an investable finance package	48
FQ 17. Do you agree with our working assumption that there is risk symmetry within the aggregate balance of the whole price control?	Chapter 1 - Ensuring an investable finance package	48
FQ 18. Do you agree with our approach to assessing financeability?	Chapter 1 - Ensuring an investable finance package	49
FQ 19. Do you agree with our proposal to adjust bucket 2 capitalisation rates from natural rates to 85% for all ET licensees to support financeability? Are there alternative measures that stakeholders consider more appropriate?	Chapter 1 - Ensuring an investable finance package	49
FQ 20. Do stakeholders have views or evidence on long-term financeability considerations, including the appropriateness of the proposed asset lives?	Chapter 1 - Ensuring an investable finance package	51
FQ 21. Do you agree with our proposal to implement the Financial Resilience measures as laid out in our SSMD and the proposed methodologies set out above?	Chapter 1 - Ensuring an investable finance package	52
FQ 22. Do you agree with the proposed position that by including robust protections within the Price Control Financial Handbook, a tax forecasting penalty is not required?	Chapter 1 - Ensuring an investable finance package	52

FQ 23. Do you agree definitions for ANDt and TDNIt should be updated to reflect the principles outlined in paragraph 7.41?	Chapter 1 - Ensuring an investable finance package	53
FQ 24. What are your views on our proposal to accelerate depreciation for new assets only in GD and is there any further evidence you would like us to consider before we reach a final decision?	No Response (Gas Sector)	53
FQ 25. Do you agree with our proposal to maintain the existing depreciation policy for gas transmission assets?	No Response (Gas Sector)	53
FQ 26. Do you agree with our proposal to maintain the existing depreciation policy for electricity transmission assets?	Chapter 1 - Ensuring an investable finance package	53
FQ 27. Do you agree with our proposals for the RAM thresholds and adjustment rates?	Chapter 1 - Ensuring an investable finance package	53
FQ 28. Do you agree with our proposal to include programmes such as ASTI within RAMs?	Chapter 1 - Ensuring an investable finance package	53
FQ 29. Do you agree with our proposals for RAV Indexation?	Chapter 1 - Ensuring an investable finance package	53
FQ 30. Is there any additional evidence we should consider to improve our setting of regulatory capitalisation rates?	Chapter 1 - Ensuring an investable finance package	53
FQ 31. Do you agree with the approach to maintain the RIIO-2 treatment for disposal of assets?	Chapter 1 - Ensuring an investable finance package	53
FQ 32. Do you agree with the proposal for the ex ante base revenue definition we will use to calculate the re-opener materiality thresholds?	Chapter 1 - Ensuring an investable finance package	53
FQ 33. Do you agree with the proposal for how we will set ODI caps and collars at DD that are fixed for the duration of RIIO-3?	Chapter 5 - Incentives	124
FQ 34. Do you agree with the proposal to move to using nominal WACC as the single uniform TVOM?	Chapter 1 - Ensuring an investable finance package	54
FQ 35. Do you agree with the proposed base revenue forecasting penalty mechanism?	Chapter 1 - Ensuring an investable finance package	54
FQ 36. Do you agree that the thresholds have been set appropriately?	Chapter 1 - Ensuring an investable finance package	54
RIIO-3 DD – Impact Assessment	Mapping to Chapter	**Mapping to Page Number**

IAQ 1. Do you agree with our approach to assessing the economic impacts of RIIO-3?	Chapter 7 - Value for Money	158
IAQ 2. What are your views on the appropriate approach to evaluation of the economic impacts of RIIO-3?	Chapter 7 - Value for Money	158
IAQ 3. Do you agree with our approach to modelling the bill impacts of RIIO-3? Please provide any additional effects or alternative measures that you think would be appropriate.	Chapter 7 - Value for Money	159

Itemisation
of additional Annexes (submitted separately)

SP Energy Networks
RIIO-T3 Draft Determination Response

Annex 2 – Finance

Annex 2.1 - RIIO-3 Cost of Equity Response DD NERA Final
Annex 2.2 - Oxera - RIIO-3 DD CAPM Parameters and Debt Based Cross checks
Annex 2.3 - US Allowed Cost Of Equity Vs Ofgem DD
Annex 2.4 - FE Updated Cost of Equity Cross Check Evidence - ENA
Annex 2.5 - SPEN - Relative Risk Assessment - Summary Report
Annex 2.6 - FE Assessing Regulators Approach to Setting the TMR
Annex 2.7 - Oxera TOs ET3 Investability
Annex 2.8 - Assessment of Ofgem T3 DD Cap Rate Adjustment
Annex 2.9 [redacted]
Annex 2.10 - Frontier Cross Checks Standards of Evidence
Annex 2.11 - ENA Liquidity+Carry Draft
Annex 2.12 - SPT depn Gap Modelling

Annex 3 – Indirects Cost Assessment

Annex 3.1 - RIIO3 Opex Cost Assessment for SPT
Annex 3.2 – RIIO-3 Indirect Cost Assessment – STC – 21-08-25
Annex 3.3 - Indirect Requirement Case Study

Annex 4 – Indirects Cost Assessment

Annex 4.1 - Oxera Ongoing Efficiency & RPEs

Annex 5 – Engineering Justification Papers

Annex 5.1 [redacted]
Annex 5.2 [redacted]
Annex 5.3 [redacted]
Annex 5.4 [redacted]
Annex 5.5 [redacted]
Annex 5.6 [redacted]
Annex 5.7 [redacted]
Annex 5.8 [redacted]
Annex 5.9 [redacted]
Annex 5.10 [redacted]
Annex 5.11 [redacted]
Annex 5.12 [redacted]
Annex 5.13 [redacted]
Annex 5.14 - [redacted]
Annex 5.15 [redacted]
Annex 5.16 [redacted]

Annex 6 – Business Plan Incentive

Annex 6.1 - RIIO-T3 - Workforce & Diversity Commitments (further Detail)

Annex 7 – Environmental Sustainability

Annex 7.1 - Net Zero Transition Plan SPEN
Annex 7.2 - Capital Carbon
Annex 7.3 - Operational Transport PCD - Data Request Sheet

Annex 8 – Incentives

Annex 8.1 - OcCS Incentive annex - Joint TO response
Annex 8.2 - SPEN Research on Behaviour Incentivisation report FINAL 26-08-2025