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Scottish & Southern Electricity Networks
TRANSMISSION

SSEN Transmission Response to RIIO2 Draft Determinations – Question Responses

September 2020

Scottish Hydro Electric Transmission plc

Contents

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1 Introduction

This document includes a full and comprehensive response to each question posed within Ofgem's Draft Determinations for RIIO-2, including the:

- Core Document;
- Electricity Transmission Annex;
- Scottish Hydro Electric Transmission Annex;
- NARM Annex; and
- Finance Annex.

In reviewing our response to each question below, it is paramount the reader has understood and is able to take account of the overall SSEN Transmission Response to Draft Determinations ('the Main Response'). Our response to each question within this document must not be considered in isolation and should be reviewed within the overall context set out within the Main Response.

In addition, our response is also supported by additional evidence from SSEN Transmission and/or external consultants, which we reference where appropriate. We cross-refer to other questions for more detail in response to specific issues. Where this is it case, Ofgem must take account of this additional information in order reach a fully informed recommendation or conclusion.

2 Core Document: consultation question responses

***Core Question 1**: What role should Groups play during the price control period and what type of output should Groups be asked to deliver? Who should be the recipients of these outputs (companies, Ofgem and/or stakeholders)?*

Purpose and Function of the Network for Net Zero Stakeholder Group

Our RIIO-T2 Business Plan has been co-created to meet the expectations and needs of energy consumers, customers and stakeholders in the north of Scotland and across GB. The focus of our Plan reflects the ambition of our stakeholders: to tackle the climate emergency, to ensure a reliable and available transmission network, to improve resilience and security of supply, to act sustainably and earn the trust of our stakeholders, and to do this cost effectively. The independent RIIO-T2 User Group played a key role in the development of our plan, providing advice, expertise and challenge on behalf of our stakeholders (as outlined in response to Core Q8). Given the invaluable input and role the RIIO-T2 User Group has played we have proposed a new stakeholder Group, 'Network for Net-zero Stakeholder Group'. The role and purpose of the Group is threefold:

1. To hold SHE Transmission to **account** on delivering the commitments made in the RIIO-T2 Business Plan settlement; in particular performance against targets and outputs (this will include reporting how we are delivering consumer value, and ensuring we are accountable if any CVP is rewarded as outlined in response to question Core Q 37 and 38 and SHET Q4); and,
2. To provide **independent scrutiny, challenge and advice** on key decisions outside the Certain View.
3. To discuss any other matters that the Network for Net Zero Stakeholder Group identify, in agreement with the business, including **preparation for RIIO-T3**.

The outputs of the Group will be minutes of meetings and an annual report. The minutes will be shared with the Transmission Executive Committee (TEC) as part of our commitment to reflect stakeholders' views in our decision-making. The purpose of the annual report is twofold; firstly, it will provide a summary to the SSEPD Board and SHE Transmission business leaders of the issues considered and the advice given, which in turn helps to support further scrutiny and accountability and, secondly to be open to all our stakeholders (including Ofgem) about the work of the Network for Net Zero Stakeholder Group, for the benefit of our customers and stakeholders as well as to outline the pertinent issues and decisions taken. To this end, the annual report will be published on the SSEN Transmission website and accessible to all stakeholders including Ofgem.

We have provided a copy of the Group's Terms of Reference attached as annex: T2BP-DD-SHE-008 SSEN Transmission - the role of Groups (Core Q1)).

In summary the Group will provide:

- Direct stakeholder input to consideration of project decisions
- Improved stakeholder engagement and awareness of SHE Transmission
- Greater transparency of SHE Transmission decision making
- Improved stakeholder understanding of decisions.

Enduring role of Ofgem's RIIO-2 Challenge Group (or similar entity)

We welcomed the independent challenge and additional scrutiny that was intended to be brought to the RIIO-2 process by the Challenge Group. We acted in good faith throughout our engagement with the Group on the development of our Business Plan. On 24 January 2020, Ofgem published the Challenge Group's report[1] outlining independent views on the energy network company Business Plans for RIIO-2.

However, based on our experience it is critical that any enduring role for the Challenge Group (or similar entity) seeking to assess and challenge the network companies' Business Plans throughout RIIO-2 and beyond must be clear and based **realistic timescales and proportionate to the degree of scrutiny undertaken of licensees' proposals.**

We have previously written to Ofgem outlining our disappointment that the Challenge Group report as delivered to Ofgem was not prepared in accordance with the Group's Terms of Reference[2] and instead that its conclusions appear to have been based primarily on the Group's assessment of earlier **drafts** of SHE-Transmission's Business Plan. The consequence of the Challenge Group's inability, most likely due to tight timescales of submission of final Business Plan and the publication of the Challenge Group's report, to undertake a **full** assessment of the Final Business Plan is that SHE-Transmission's significant efforts in developing a robust and evidence-based Business Plan have been unfairly characterised and misrepresented in the Challenge Group Report.

We appreciate that the task set for the Group by the Terms of Reference was challenging, and that it is clear from the text of the report that the Group has its own misgivings about the robustness of its analysis. It is therefore important that any future report stops short of reaching conclusions that it is not possible to reach without a full and thorough review of all the evidence which, as the price control review process demonstrates, which takes months and intense bilateral engagement.

Despite our view that the current format of the Challenge Group is no longer relevant beyond the Business Planning process, should Ofgem decide a similar group is required, any Terms of Reference must be amended to reflect output that delivers benefit for consumers, whilst affording any group with an opportunity to review information at an appropriate level of detail in order to reach accurate conclusions. This is particularly important if the enduring role for any group is at a sector-level (as opposed to one group per company). We believe that the group should focus its effort on areas of strategic themes (Net Zero, network reliability, delivery of outputs etc) and sharing of best practice across industry in order to drive better outcomes for consumers. Adopting this approach would not require a 'root and branch' examination (as per the current Challenge Group Terms of Reference) but allow the group to focus on sharing best practice and recommendations at a sector level leading to benefits for consumers.

[1] https://www.ofgem.gov.uk/publications-and-updates/riio-2-challenge-group-independent-report-ofgem
[2] https://www.ofgem.gov.uk/publications-and-updates/riio-2-challenge-group-terms-reference

***Core Question 2:** What role should Groups take with respect to scrutinising new investment proposals which are developed through the uncertainty mechanisms?*

As noted in our response to Core Q1, the explicit purpose of our Network for Net Zero Stakeholder Group is to provide independent scrutiny, challenge and advice on key decisions outside the Certain View. This will include new investment proposals under uncertainty mechanisms.

The Network for Net Zero Stakeholder Group will provide the business with expert challenge, feedback and opinion on the topics presented at meetings. This will take the form of recorded recommendations, as required by the Chair. The Network for Net Zero Stakeholder Group is not required to vote on or formalise decisions including in relation to investment under the uncertainty mechanisms. It is expected that the Network for Net Zero Stakeholder Group will provide input for improved outcomes in relation to stakeholder engagement associated with new investment proposals.

The main focus areas of the Group in relation to investment decisions will include, (but is not limited to):

- The stakeholder engagement we have undertaken to inform our proposals
- The range of scenarios the company has considered to anticipate future network requirements and the company's approach to managing uncertainty and associated risks. This should include testing the business against the full range of scenarios (both significantly lower or higher generation or demand) to ensure the Business Plan remains robust in the face of unforeseen changes
- What alternative options to the investment proposals has the company considered, including from parties offering alternative and non-network-based solutions
- Any issues of particular relevance to a local region – including any significant investment choices in their area, and provide challenge to decisions made by the company when considering competing interests and perspectives

***Core Question 3**: What value would there be in asking Groups to publish a customer-centric annual report, reviewing the performance of the company on their Business Plan commitments?*

Our Network for Net-zero Stakeholder Group will prepare a customer-centric end of year report to be published on the SSEN website. The purpose of the annual report is twofold:

1. Provide a summary to the SSEPD Board and Transmission Executive Committee of the issues considered and the advice given by the Group. The value of this is to ensure the Group's accountability in fulfilling its role of providing challenge, input and advice to SHE Transmission's business decisions.
2. To be transparent about the work of the Network for Net Zero Stakeholder Group, for the benefit of our stakeholders including consumers, ensuring that SHE Transmission remains accountable to stakeholders in delivering our RIIO-T2 Business Plan. For example, ensuring there is clear measurement and reporting on SHE Transmission's Five Clear Goals.

***Core Question 4**: What value would there be in providing for continuity of Groups (albeit with refresh to membership as necessary) in light of Ofgem commencing preparations for RIIO-3 by 2023?*

We believe striking the right balance between continuity and unequivocal challenge is essential for the Group fulfilling its role. We have undertaken a review of our current User Group and we have updated membership to reflect the necessary skills and expertise required in order to provide robust challenge to our business.

As part of this re-fresh we considered which stakeholders would have either the expertise required to represent our stakeholders and/or the knowledge of our Business Planning process to provide a level of continuity from RIIO-T2 preparations. Given the complex nature of the regulatory settlement process and transmission industry, this produces a small pool of highly experienced individuals, which has resulted in some previous members of our RIIO-T2 User Group being selected.

We believe our new Group will provide continuity with two-thirds of our new Network for Net-Zero Stakeholder Group having existing experience and knowledge from our RIIO-T2 Business Plan development to hold us accountable for delivery. The remaining one-third of members are new to the Group to reflect the expertise required in consumer insight, regulatory challenge, policy development and customer expectations (please see annex T2BP-DD-SHE-003 SSEN Transmission - Group Bios for the new Groups' profiles).

We will consider refreshing the Group as deemed necessary; for example, if the Group's expertise requirements change over the RIIO-T2 period. It should also be noted that the Group's Chair will invite other stakeholder representatives to discuss a specific topic; for example, if a session was focusing on consumers' bills, we may invite a consumer representative group like Citizens Advice Scotland.

***Core Question 5**: Will the combination of the two proposed Licence Obligations support the delivery of a digitalised energy system and maximise the value of data to consumers?*

Yes, we agree in principle that the combination of the two proposed Licence Obligations (companies to publish regular updates to their digitalisation strategy and action plan and companies to work in accordance with the principles set out in Ofgem's data best practice guidance) support the delivery of a digitalised energy system and maximise the value of data to consumers. SSE looks forward to engaging further in the consultation on the final draft of the data best practice guidance in due course to determine how this will work in practice.

In 2019, the Energy Data Task Force (EDTF) published a report targeted at informing the development of a strategy for a modern digitalised energy system.

https://es.catapult.org.uk/reports/energy-data-taskforce-report/

The report defines five recommendations on how data can assist with unlocking the opportunities provided by a modern, decarbonised and decentralised Energy system at the best value to consumers:

- Digitalisation of the Energy System
- Maximising the Value of Data
- Visibility of Data
- Coordination of Asset Registration
- Visibility of Infrastructure and Assets

In order to put these recommendations into action, the Energy Networks Association (ENA), representing transmission and distribution network operators for gas and electricity in the UK and Ireland, has created a Data Working Group with further sub-groups formed to address specific aspects of the report. The Department for Business, Energy and Industrial Strategy (BEIS), Ofgem and Innovate UK have commissioned the Energy Systems Catapult to develop Data Best Practice Guidance to help organisations understand how they can manage and work with data in a way that delivers the vision outlined by the Energy Data Taskforce.

We are part of the ENA Data Working Group which has been formed to collaboratively address data issues, access new datasets and identify opportunities to derive value from existing datasets and to work with Ofgem, BEIS, Innovate UK and industry stakeholders to progress the recommendations of the Energy Data Task Force and deliver modern, digitalised Energy Networks for customers. As part of this collaborative approach we will continue to engage with stakeholders on use cases and data provision, utilising a data triage process which presumes open data whilst maintaining cyber security and data privacy best practice.

We are very conscious that categorisation of data which should comply with data best practice guidance must be needs driven and driven by stakeholders'/users' needs. Planned investments and ongoing services must relate to the needs of direct users and ultimate benefits relate to wider stakeholders' needs. We take an open-minded view as to who the 'users' of energy systems data might be and we recognise that increasingly the users of energy system data are intertwined with many other systems, such as those of other utilities, finance, transportation and housing.

As we noted within supplementary question SHETL_SQ_CA_55, the recommendations of the Energy Data Task Force (EDTF) are specifically addressed in page 11 of the SHE Transmission Digital Strategy (T2BP-PAR-0006).

***Core Question 6:** Do you agree with our proposed frequency for publication of updates to the digitalisation strategy and the digitalisation action plan, respectively?*

We agree with the proposed frequency for updates of both the digitalisation strategy (at least every two years) and the digitalisation action plan (at least every six months).

No supplementary question was raised on this issue following submission of the Business Plan.

***Core Question 7**: What kinds of data do you think should comply with the data best practice guidance to maximise benefits to consumers through better use of data?*

At a high level and on a preliminary basis, we consider that the following types of data should comply with the data best practice guidance to maximise benefits to consumers through better use of data:

- Principal energy network assets (e.g. circuits and sites, including basic attribution such as voltage level, pressure system level, etc.) (Subject to Cybersecurity and Critical National Infrastructure limitations)
- Assets locations (Subject to Cybersecurity and Critical National Infrastructure limitations)
- Ownership and operation details on assets
- The capacity of assets
- The level of utilisation of assets
- The performance of assets (e.g. fault history)
- Where opportunity for flexibility services exist
- Data on production resources (PV, Wind, Thermal), flexible resources such as storage or flexible demand and their capacities as well as the point of connection to the wider system.
- Data on the configuration and connectivity of the system: what is connected where and how the elements of the system connect to each other to enable users to understand how the system is configured and how they are connected to it.
- Technical data on the components of the system: their electrical parameters (resistance, reactance etc), technical capabilities (thermal ratings, voltage ratings etc)
- Geospatial data to facilitate use cases such as Constraint Zones or Safety information for those working near live systems.
- Operational data such as system operator forecasts for supply and demand, network performance data and system operator information on Resources dispatched, constrained and Flexibility called on and real time operational data.

We plan to engage further with Ofgem in due course in the consultation on the final draft of the guidance on data best practice.

As noted within our response to Core Q5 we will continue to engage in the Data Working Group formed to progress the recommendations outlined within the Energy Data Task Force (EDTF) report published in 2019.

***Core Question 8**: Do you agree that the Groups could have an enduring role to work with the companies to monitor progress and ensure they deliver the commitments in their engagement strategies?*

Yes, while the appointment of a User Group was a mandatory requirement of the RIIO-2 regulatory process, we welcomed and supported this enhanced engagement and innovation. The contribution of the User Group was invaluable in strengthening the quality and ambition of our RIIO-T2 Business Plan. In establishing our Network for Net Zero Stakeholder Group we sought to build upon and learn from how the RIIO-T2 User Group influenced our decision making.

Our Stakeholder Engagement Strategy puts stakeholders at the centre of our business strategy and decision making. One of our objectives is to work with stakeholders in our planning and delivery and strive to achieve mutually acceptable and agreed outcomes. We currently involve stakeholders in our construction and business projects. By identifying and engaging with stakeholders earlier, creating opportunities to co-create solutions, and holding regular engagement throughout their involvement with us, we can co-create solutions which are acceptable to impacted stakeholder groups. The enduring role of the Network for Net Zero Stakeholder Group includes assessment of stakeholder interesting in performance and project investments, which will contribute to monitoring progress on this objective.

***Core Question 9**: Do you agree with our proposal to accept the proposals for an ODI-R for BCF and the other proposals set out above as EAP commitments and to require progress on them to be reported as part of the AER?*

Yes, we agree with Ofgem's proposal to accept the proposals for an ODI-R for BCF and the other proposals set out above as EAP commitments and to require progress on them to be reported as part of the Annual Environment Report (AER). However, we remain concerned over the lack of recognition of ambition from our RIIO-T1 track record (from both EDR and SF6 performance) and RIIO-T2 EAP commitments. Despite demonstrating leadership in a number of areas as verified by our independent benchmarking, Ofgem appears to assess all TOs as providing equivalent value to current and future consumers, when this is evidently not the case. This has not been reflected in Ofgem's Draft Determination in regard to ODIs and the CVP.

Please refer to response ETQ6 for the need for a consistent approach for an Environment Score card incentive (ODI-F). In addition, our Environmental and Sustainability ambition has not been recognised in our consumer value proposition for the Business Plan incentive (also in response SHET Q4).

As noted in our Sustainability Action Plan Section 1.4.3 we are committed to transparent reporting and continuing to work with other TOs and our stakeholders to agree common reporting methodologies and metrics as part of the Annual Environment Report (that will be included in SHE Transmission's Annual Performance for Society Report).

***Core Question 10**: Do you agree with our proposed RPEs allowances? Please specifically consider our proposed cost structures, assessment of materiality, and choice of indices in your answer.*

We have seen little to no evidence presented by CEPA[3] or Ofgem in its assessment of RPEs in the Draft Determinations which provides sufficient comfort that this has been carefully considered and evaluated. In our Business Plan, we provided significant evidence around the volatility of indices and in particular the unreliability of using certain indices to set cost allowances. We also noted that for the indices to be truly reliable they would have to reflect the underlying cost base and in particular translate as changes in our expenditure. As part of that we would be required to manage the risk by placing contracts with the supply chain that reflected these indices therefore protecting the company from downside risks over the course of RIIO-T2.

We equated this to two different options, a) we pass this risk on to the supply chain which would ultimately cause an increase in costs to consumers, or b) we absorb the risk and try to manage the volatility in indices over the T2 period. We therefore believe that RPE indexation is likely to increase costs to consumers to this new risk for ongoing management during RIIO-T2. As a result, we proposed that no indexation of RPEs was used during RIIO-T2 with the only category that warranted a reliably and steady estimate of RPEs was in labour costs. This appears to have been ignored in Ofgem's Draft Determinations as well as CEPA's analysis. We also note that CEPA has not considered the volatility of indices except for evaluating the impact on totex at a high level[4].

- **Unfortunately, despite repeated requests for the data and analysis to support these conclusions, cost structures or assessment, Ofgem has not provided this during the consultation period.**

We are therefore unable to provide a full assessment of the proposals, their robustness or validity other than noting its errors and absence of data. We do also note that the underlying calculation for the opening allowance was also not provided by Ofgem during the consultation period either. We believe significant further consultation and engagement is required on RPEs and in particular with reference to the overlap with ongoing efficiency as we noted in our Business Plan[5]. The overlap and possible double count is a serious matter and we have provided evidence of this with supporting evidence from Oxera[6]. This is outlined extensively in the report provided by Oxera and our response to ongoing efficiency.

[3] CEPA (May 2020), 'RIIO-GD2 and T2 Cost Assessment - Frontier Shift methodology paper'
[4] Ibid. para 4.3.3
[5] SHET RIIO-T2 Business Plan, 'A Network for NetZero'
[6] Oxera (Sept 2020), 'Critique of RIIO-2 Ongoing Efficiency Analysis'

***Core Question 11**: Do you agree with our proposed ongoing efficiency challenge and its scope?*

We do not agree with Ofgem's ongoing efficiency challenge or its scope, as it has been presented within the Draft Determinations. In arriving at this conclusion, we have sought the expert advice of Oxera in reviewing Ofgem's Draft Determination proposals and, in particular, the evidence on which these are based[7]. We rely on that report in full and do not seek to replicate it here but have focused on the key points raised.

Both individually and collectively, the issues identified in CEPA's assessment and Ofgem's interpretation and application of these demonstrate that Ofgem has failed to reach a reasonable conclusion and is therefore proposing reductions in price control allowances that are in error.

Ongoing efficiency under RIIO

We agree that the RIIO mechanism should encourage ongoing efficiency improvement by individual companies and across the industry. Our previous responses to industry discourse on Totex, incentives and efficiency demonstrate we strongly support an effective framework that encourages sustained improvement in productivity based on clear incentives that encourage the right behaviour from network companies.

Our Network for Net Zero Business Plan demonstrated that commitment. Within our Plan[8] we established how we deliver a minimum of £123m ongoing efficiency benefit that customers would benefit from during RIIO-T2. These included:

- Offsetting Real Price Effects and Ongoing Efficiency;
- Reduction in average asset costs from RIIO-T1 to RIIO-T2 through improved procurement and design, over and above ongoing efficiency of 0.3-0.8%, of £60-73m;
- Lower expenditure through ongoing Innovation from which customers would benefit £42-55m; and
- A lower Risk and Contingency uplift of 8.2%, embedding net totex productivity gains from RIIO-T1, benefiting customers by £10-39m.

Each of these benefits were explained and evidenced within our Business Plan.

Ofgem's Draft Determination ongoing efficiency proposals

Ofgem's efficiency proposals suffer from a number of errors which lead to unjustified reductions in totex allowances. These are summarised as follows in Table 1.

[7] Oxera: Critique of RIIO-2 ongoing efficiency analysis, August 2020
[8] RIIO-T2 Business Plan: A Network for Net Zero, December 2019, page 41; Efficient Capital Investment: Benchmarking and Cost Metric, section 6; and, Oxera: Scottish Hydro Electric Transmission's cost assessment, December 2019.

Core Q11 Table 1 – summary of identified issues within ongoing efficiency proposal

AREA	ISSUE	ASK
Double counting embedded efficiency	**Methodology / model error:** Ofgem claims to have adjusted for embedded efficiency in our plan. We find no such adjustment in its Cost Assessment models. §3.61 ET Annex	Ofgem must adjust for the identified and embedded efficiency in network plans prior to overlaying ongoing efficiency.
Double counting innovation potential	**Counting innovation benefits twice:** By using the productivity improvements exhibited by UK industries, Ofgem's methodology already captures improvement from Innovation activity.	There is no justification for an additional innovation efficiency stretch. This should be removed ahead of Final Determinations.
Attributing Innovation benefits	**Failure to attribute benefits correctly: I**nnovation will not always reduce TO totex, e.g. constraints. Ofgem assumes these benefits are all realised in TO totex.	Adjust proportionally for the spread of innovation benefits across industry sectors and intangible outcomes.
Ofgem's interpretation of CEPA's review	**Unjustified application:** Ofgem has used CEPA's report and interpreted elements, against CEPA's (flawed)advice, without justification. These include the exclusive use of Value Add (VA) productivity measure; failure to consider future growth predictions	Adjust the ongoing efficiency proposals to reflect the compound impact of the errors identified by Oxera.
CEPAs assumptions and data choices	**CEPA analysis:** the use of incorrect comparator sectors and unjustified weighting; the reference time period selected;	Adjust the ongoing efficiency proposals to reflect the compound impact of the errors identified by Oxera.
Result	**X Draft Determination proposals far exceed the levels justified by evidence and more than double count the efficiency already incorporated into our Plan**	**✓ There should be no ongoing efficiency targets over and above existing plan proposals.**

Double counting – embedded efficiency

Ofgem asked CEPA to consider the range of ongoing efficiency that a network might achieve in the future. CEPA's report contains a number of assumptions which are reviewed in more detail by Oxera. However, while CEPA includes an incomplete list of some of the efficiency assumptions made in our plan and other networks, it does not attempt to adjust its proposed efficiency range for those.

In the Draft Determinations Ofgem then states that ‘p*rior to applying our OE challenge, we removed any network company-proposed OE from its plan*’[9].

We find no evidence that Ofgem has made such an adjustment prior to applying its ongoing efficiency challenge. Having checked the models which it has subsequently shared, we can see no modification of the forecast expenditure which we included within our Business Plan. Ofgem’s cost assessment process therefore includes our individual network efficiency assumptions.

Moreover, to the extent that a company proposes efficiency gains in one activity over another, Ofgem’s cost assessment capping methodology, choosing the lower-of, will lead to the industry carrying more embedded efficiency than they individually proposed. This exacerbates the core error, namely the failure to remove forecast efficiency prior to applying an ongoing efficiency assumption.

- **Ofgem should correct for the error between its stated methodology and its models by accounting for the £100m+ of benefits already included in our Plan.**

Double counting – innovation within industry comparator sectors

Ofgem has also asked CEPA to estimate the ongoing benefit which customers might see from the innovation funding provided during RIIO-T1. CEPA does not estimate the benefits arising, but rather what would be a reasonable expected benefit based on a reasonable return on the innovation funding provided, 0.2% pa.

CEPA, however, does not adjust its estimate to reflect the innovation benefits already present within the comparator sectors, which are used to derive the core ongoing efficiency ranges. This therefore creates a double count when overlaying a further estimate of innovation benefits.

CEPA also prompts Ofgem to consider what level of RIIO-T1 innovation is already baked into each network’s Plan. Ofgem states that it has considered this possibility and can dismiss it. However, it provides no evidence on how it has reached such a conclusion, which is plainly inappropriate.

- **Ofgem should remove the 0.2% innovation uplift as this is a component of the core efficiency measure.**

Attributing innovation benefits incorrectly

While Ofgem acknowledges that some gains from innovation may not be financial, e.g. service quality or other outputs, it dismisses this as an effect which it needs to adjust for on grounds that financial benefits are ‘likely’ to be greater. It presents no evidence for this.

Neither CEPA nor Ofgem consider whether the innovation gains made during RIIO-T1 actually accrue to the TOs through lower totex. We have provided some examples where the innovation outcome was a benefit to the GB energy industry, and therefore customers, but crystallises through outcomes such as lower constraint costs.

[9] Ofgem: Consultation - RIIO-2 Draft Determinations – Electric Transmission Annex, §3.61

- **Ofgem therefore must adjust its innovation assumptions to ensure it is only considering tangible transmission totex benefits.**

Ofgem's interpretation and application of CEPA's review

In our previous responses and our Business Plan we supported the derivation of ongoing efficiency from sources such as EU KLEMS. However, we have consistently cautioned against over reliance on one measure of productivity over another. Rather, we supported the use of Gross Output (GO) and Value Added (VA) approaches.

Having listed the benefits and limitations of both measures, CEPA concludes, '*it is typically seen as good regulatory practice to consider the information provided by both methods when developing a range for ongoing efficiency estimates. This is consistent with Ofgem's approach in RIIO-1 and with Ofwat's approach in PR19.*'

Ofgem, however, dismisses the GO measure due to '*practical difficulties*' even though CEPA's report addresses these through a consistent and widely accepted conversion. Ofgem makes no attempt to consider whether these practical difficulties are valid to dismiss the GO measure but does confirm that '*excluding them from our analysis results in a higher proposed level for ongoing efficiency*'. It would not be unreasonable to conclude that Ofgem has sought measures which display the largest ongoing efficiency.

On this issue and others, Ofgem has interpreted CEPA's recommendations and in most instances adopted the extreme or dismissed the point of caution. This includes its failure to reflect future economic factors and the selection of the upper end of CEPA's productivity ranges. These issues are considered in more detail in Oxera's accompanying report.

- **Ofgem should adopt the modified efficiency ranges proposed and justified by Oxera in its independent review.**

CEPA's assumptions and data choices

Within its report, CEPA choses to adopt a number of assumptions to derive its recommended efficiency range. We believe that a number of the assumptions adopted cannot be considered to be reasonable or balanced, particularly in light of concerns or issues which CEPA also flags. The following are examples of this behaviour.

CEPA relies on an all industries comparator set. There is no compelling reason given to include the technological and efficiency gains seen in sectors such as 'agriculture, forestry and fishing' and 'accommodation and food services' when establishing the future potential of the energy sector.

Furthermore, CEPA highlights which sectors are relevant comparators for the energy industry. However, it then fails to reflect the power of these sectors to explain productivity changes in its choice of weighting comparator sets. Rather, it reflects the importance of each sector to the UK economy and not the energy industry.

We also flag issues with the interdependent nature of some of CEPA's assumptions and conclusions and how flaws in one area can lead to incorrect conclusions elsewhere. For example:

CEPA notes the benefits of incorporating the GO measure of productivity in the final efficiency targets. It recommends that Ofgem consider what weighting should be attributed to GO versus VA. It suggests caution because '*GO measures sit close to or below even the lowest ongoing efficiency values **proposed** by any of the network companies*[10]'

CEPA summarises the efficiency **proposals** made by networks and that we acknowledge that ongoing efficiency of 0.3-0.5% should be possible to achieve.

However, it fails to recognise that **we proposed and have built into our plan** efficiency improvements that deliver £123m-£178m in addition to the 0.3% capital efficiency improvements we recognised above. CEPA's summary of network efficiency proposals is therefore incomplete and inadequate.

CEPA is therefore wrong to justify its rejection of the GO measure on the premise that it was close to or below network forecasts. In fact, when assessed alongside the improvements that we have embedded within our plan, the GO would appear too high.

This error in turn leads to an incorrect Ofgem assumption that an additional £98m of efficiency is warranted over and above the £123m - £178m+ of benefit already identified.

These issues, and others, are considered in more detail in Oxera's accompanying report.

- **Ofgem should consider the evidence-based challenge of CEPA's core assumptions. It should compare these to the step change in efficiency already embedded within our Plan and, using its principle of capping, remove all and any ongoing efficiency adjustments from the Final Determinations.**

[10] CEPA: RIIO-GD2 and T2: Cost Assessment – Frontier shift methodology paper, §3.6

***Core Question 12**: Do you agree with our proposed common approach for re-openers?*

Before we answer the question there are a number of important points to highlight regarding re-openers:

- **Policy is unclear:** the re-opener policy in the Draft Determinations is not clear. It is in multiple sections and which re-openers the policy position applies to isn't always obvious. This has led us to developing the table below, approved by Ofgem, to set out our understanding of where elements of the "common approach" apply. One example is with regards to Close Out assessment. It is unclear what Ofgem means for each individual re-opener. Does it mean a true-up of allowances to costs incurred (if so, is this symmetrical or asymmetrical) or does it mean another re-opener application window? We have set out where we believe "true up" and "logging up" applies at Close Out (see appendix "T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals").

- **Application of the re-openers:** there are significant outstanding questions about the practical application of the re-openers. We note that there are some promises of guidance documents to follow but it is not clear when that will be and what that guidance will contain. We ask that Ofgem:

    - sets out a clear list of all guidance documents and a timetable for when each will be provided;
    - within that guidance set out that it will undertake decision-making in time for the Annual Iteration Process (AIP) within the relevant years. This is critical given the potential expenditure (and, hence, cashflow implications) associated with re-opener items; and
    - provide a clear commitment to reach a decision on all re-openers within six months of submission.

- **Changing policy positions:** in discussions with Ofgem post Draft Determinations publication, the policy appears different. Whether this is due to mis-explanation or movement from Ofgem isn't clear. For example, Ofgem's proposed application of the 1% materiality for the third party driven elements of MSIP (discussed below) appears to have changed since the publication of the Draft Determinations.

- **Scope of this response:** this response refers only to the common approach for re-openers. It does not directly respond to the fact we disagree with Ofgem's proposed rejection of a re-opener for legislative policy changes – particularly regarding landowner compensation and Brexit import changes (see our answers to core Q20 on legislation, policy and standards and ET Q13 on MSIP).

Overall, we would welcome a further update (clarifying points raised by industry parties) on re-opener policy from Ofgem as soon as possible, and in sufficient time for stakeholders to respond prior to Final Determinations.

Turning to the question as set, we answer it with reference to table below which details where the "common parameters" apply. Our response to each re-opener is considered in the relevant re-opener question (noted in the first column of the table) but we repeat the areas of particular concern/disagreement here with regards to the application of common approach. These are highlighted red and amber in the table, where red indicates significant concern.

Core Q12 Table 1 – summary of our response to common re-opener proposals

Re-opener Name	# of re-opener windows and when	Authority Re-opener applicable	Materiality Threshold	Aggregation applicable
Cross Sector Re-openers				
Cyber Resilience OT (Core Q6)	a) April 2021; b) January 2023	Yes	None	No
Cyber Resilience IT (Core Q6)	a) April 2021; b) January 2023	Yes	None	No
Information Technology and Telecoms (IT&T) (Core Q18)	a) April 2021; b) January 2023	Yes	None	No
Physical Security (Core Q22) (Core Q19)	a) 2023; b) Close Out (2026)	Yes	**Ofgem:** 1% of annual base revenue **SHET:** None	Yes
Net Zero (Core Q23)	Ongoing	**Ofgem:** Yes exclusively **SHET:** licensees can trigger too	**Ofgem:** 1% of annual base revenue **SHET:** None or regulatory burden value (c£1m-£2m) for all NZ re-openers collectively	TBD
Whole systems 'Coordinated Adjustment Mechanism' (Core Q13-15)	TBD	No	None	No
Pension scheme established deficit	Triennial review	Yes	N/A	N/A
Tax liability allowance	Ongoing	Yes	0.33%	No
ET Sector Re-openers				
Large Onshore Transmission Investments (LOTI) (ET Q10)	Ongoing	No	£100m+	No
MSIP – third party driven re-opener elements (ET Q13)	**Ofgem:** January 2024 and true up at Close Out **SHET:** January 2024 and Close Out for areas unforeseen in Jan 2024 window	No	**Ofgem:** 1% annual base revenue(but unclear if 1% applies to each component or combined) **SHET:** None or regulatory burden value (c£1m-£2m)	TBD
MSIP – generation and demand connections (ET Q13)	**Ofgem:** January 2024 and true up at Close Out **SHET:** ongoing	No	**Ofgem:** £25m-£100m **SHET:** <£100m	TBD
Legislative or policy changes (Core Q20)	TBD	TBD	TBD	TBD

Re-opener Name	# of re-opener windows and when	Authority Re-opener applicable	Materiality Threshold	Aggregation applicable
Pre-Construction Funding (ET Q13)	**Ofgem:** *NO REOPENER* Close Out only **SHET:** annual c1 March (1 month after publication of NOA)	No	None	No
Visual Impact Provision (VIP) (ET Q7)	Ongoing	No	None	No
SHE Transmission Re-openers				
Exceptional Subsea Cable Fault Costs (SHET Q12)	a) January 2024 and b) Close Out	Yes	**Ofgem:** 1% of annual base revenue **SHET:** None or regulatory burden value (c£1m-£2m)	Yes

MSIP

Please see our full response to MSIP (ET Q13) and the volume driver (Core Q22 and Volume Driver Supplementary Paper).

As set out in further detail below, we have two major concerns with the MSIP.

The first is that a restricted re-opener window for connections related projects not eligible (under Ofgem's current proposals) for the volume driver would be unworkable in practice.

The second, is that the suggestion by Ofgem (post publication of Draft Determinations) that the materiality of each component part of the "third party driven re-opener element" will carry a 1% materiality threshold would require TOs to carry a risk of up to 3% of annual base revenue in relation to the MSIP areas – a wholly unacceptable level.

Volume Driver Project Window

The use of the common principle of a re-opener window (in January 2024) for MSIP projects which are unsuitable for the volume driver is unworkable in practice. With a window for networks to apply for funding restricted to 2024, T2 will be largely complete before the funding is approved and released. This is therefore an ineffectual mechanism as currently designed.

As noted in our response to ETQ13, we expect the next round of CfD to take place towards the end of 2021. To enter into the CfD auction a generator must have a grid connection contract with a TO that is energised in 2025/26. Yet, with a window for the TO to apply for funding to build the infrastructure for the connection restricted to January 2024, approval will then be mid/late-2024. This is simply unworkable as we can't commit to build at risk.

Ofgem must change the MSIP re-opener window for medium sized projects unsuitable for the volume driver to an "as required" basis as set out in our Business Plan (the equivalent of MSIP was our High Value Project Re-opener (HVTP) – see pages 81-82).

For the avoidance of doubt, we would accept one in-period window and one close out window for the "third party driven re-opener elements" listed in paragraph 4.57 of the Electricity Transmission

Annex Document. This is on the provision that the close out window allows for the submission of costs incurred post January 2024 to address such third party driven requests that could not be foreseen at the January 2024 window.

Materiality for re-opener elements

We disagree with the 1% materiality for physical site security, subsea cables, Net Zero and MSIP.

In setting a materiality threshold, it is important to be clear on the purpose and intent of the threshold. Our understanding is that the threshold is intended to avoid vexatious or trivial use of the reopener. In that context, a threshold tied to base revenue is inappropriate. Instead, the threshold should be set at a fixed value to reflect the regulatory burden associated with undertaking the assessment. In addition, the threshold should take due account of the licensees ability to control the costs. Where there is no control, then there should be no materiality threshold.

For MSIP, Net Zero and subsea cables, we propose that if the value in question (i.e. underspend) exceeds the value of the regulatory burden of undertaking the ex post efficiency review then it reasonably follows that a re-opener should be triggered (regardless of what elements that does or doesn't comprise in the case of MSIP). If not, it shouldn't be triggered. We do not believe that a proportion of annual base revenue is an appropriate trigger threshold. Instead the trigger should be a fixed absolute value. We suggest this be set at c£1m-£2m.

For physical site security we propose no materiality (see Core Q19).

For the avoidance of doubt:

- For **MSIP** we disagree with Ofgem's 1% of annual base revenue proposed materiality, regardless of whether it applies to each area bulleted in paragraph 4.57 of the Electricity Transmission Annex of its Draft Determinations[11] individually or whether it applies to the areas collectively as clearly intended from the following exert from paragraph 4.57:

  > "the *total* [emphasis added] requested funding in relation to the following areas would need to meet our common de minimus (sic) limit of the 1% of annual Base Revenue"

- For the **Net Zero** reopener any materiality should apply to the total number of re-openers triggered and not to each individual re-opener.

It follows also that we also disagree with the 3% aggregation across all re-openers.

We make two particular points:

- **Lack of risk analysis or proportionality assessment:** the 1% separate threshold and 3% aggregation has not been subject to any analysis of proportionality or associated risk to consumers or licensee.

[11] Ofgem suggested at a joint TO meeting that the materiality would apply to each bullet and not collectively.

- **TOs can't manage the risk of the investment need that is driven by third parties**: the areas listed in the aforementioned paragraph (4.57) for MSIP, for physical site security and for subsea cables, are entirely outside the TOs' control. For example, a direction from BEIS to protect a specific site from flooding, additional requirements following the introduction of new Blackstart standards currently being discussed by BEIS, or a formal request by the ESO to undertake work to manage constraints on the GB system are all outside our control.

While it is appropriate to seek to avoid trivial or vexatious re-openers, that is exactly the purpose of the above threshold and the restricted windows. With these in place, both the regulatory burden and risk is being managed. To add additional significant risk to TOs is entirely unjustified and out of step with previous price controls.

Pre-construction Funding

We set out in detail our position on pre-construction funding in question ET Q11 and associated documentation. Pre-construction is not only vital to demonstrate the need for investment, the comprehensive optioneering, and stakeholder engagement, but fundamentally to ensure delivery is on time and under budget. All of this is a requirement of making high quality LOTI submissions but yet Ofgem is neither providing sufficient pre-construction in our baseline nor an in-period uncertainty mechanism.

The fundamental issue with Ofgem's uncertainty mechanism proposals is that an end of period assessment will require us to spend £100s million at risk. Uncertainty about future regulatory approval for expenditure will naturally make licensees more cautious about being innovative or proactive in these activities, particularly in the knowledge of Ofgem's stated expectation that costs should rarely exceed 2.5% of the project value.

Not only does pre-construction funding need to go back in our baseline to make large projects a viable mechanism for delivery of Net Zero projects, we require in-period adjustments for large strategic schemes that emerge or where there is a significant change in scope for those schemes in our baseline. We suggest that this is through an annual re-opener that takes place one month after the publication of the Network Options Assessment (NOA). Please see ET Q11 for more details.

This will manage both company risk (by providing funding when required) and consumer risk (through the end of period true-up – see our appendix "T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals). We accept a timely and proportionate ex-post symmetric true-up as our core aim is efficient project development, not to outperform pre-construction allowances.

Additional observations

Aggregation: Ofgem states that each re-opener must reach 0.5% of base revenue before it can be subject to the 3% aggregation. We do not agree with the aggregation or with the proposed 1% materiality as set out above. For completeness, we also do not believe there is any need for this parameter. Regardless of reaching 0.5% or not, if the collective risk exceeds 3% (or a more reasonable level as we suggest[12]) that should be enough to trigger the aggregation. The 0.5% is irrelevant to that collective risk carried by the TO.

Close Out: we agree that Close Out is required in the areas noted as having a close out reopener window. We discuss this in our appendix “T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals”. We also agree that close out is required where there is a Price Control Deliverable (PCD) but this should be considered as part of the PCD framework (see our response to SHETQ3) and we do not discuss this here. We ask that Ofgem is explicit on this in its Final Determinations to avoid confusion of what is part of the Close Out assessment and what that assessment entails; an issue that has been a problem in RIIO-T1. For example, is it another re-opener window to recover costs incurred since the previous window or is it a true-up of costs (see our aforementioned appendix).

Authority Trigger: there is an asymmetry where the Authority can trigger a re-opener at any time, while licensees have (largely) fixed windows and notification requirements. We believe the Authority trigger must align with the windows (where they apply) otherwise unexpected triggers can become unmanageable for all parties, particularly in a price control where UMs will play an increasingly large and important role. This must be managed. At a minimum, we would expect a commitment to upfront engagement with affected licensees and stakeholders.

Common principle requirements: Ofgem, in its Final Determinations, should set out a table similar to that above to be transparent on where the common principles do or do not apply. As currently set out in Draft Determinations this was challenging to identify.

[12] We do not believe 3% in the Draft Determinations low return high risk price control is at all reasonable from Ofgem.

***Core Question 13**: Do you agree with our proposals on a materiality threshold, a financial incentive, a 'foreseeable' criterion, and who should trigger and make the application?*

No. While we broadly accept the decision to remove the 'foreseeable' criterion and materiality threshold, we remain concerned with the decision to provide **no financial incentive** and we believe that both parties should be able to trigger and make the application.

In our response to Ofgem's informal consultation on the CAM (28 April) we stated that "We do not believe Ofgem's proposed approach will incentivise the correct behaviour and potentially result in hesitancy to participate as networks seek to avoid a potential reduction in RAV as a result of transferring base allowances"

Our position has not changed. As set out below, **the costs of delivering whole system solutions are significant**. Accordingly, any reward associated with the CAM should be both strong and certain enough to incentivise a **culture of collaborative working** to deliver an overall benefit of consumers.

Ofgem's assessment that this culture already exists or is business as usual for network operators is inaccurate. This is a new behaviour and new set of working practices requiring incentivisation (See Table 2). Due to the innovative and experimental approach of whole system solutions, the potential cost of developing a whole system approach is not insignificant. SSEN's Shetland New Energy Solution Project is an ideal real-world example of the associated costs. The project spent in excess **of £3m seeking to develop a whole system solution to the problem of security of supply on Shetland.** As demonstrated through our experience of Shetland, network owners will incur costs through participating in the development and assessment of whole system solutions and will only be incentivised to proceed with such products if they are able **to recover their costs at a minimum**.

The worked example below demonstrates how the CAM proposal could operate in practice so as to disincentivise whole system development.

Core Q13 Table 1 - Illustrative CAM proposal

	RIIO T2 BAU investment	CAM (Current proposal)	
Baseline allowance	£100m	£100m	
Development funding	£1m	Transmission £1.5m (additional cost due to WS requirements)	Distribution £1m
Final Cost	£90m	£85m (Distribution)	
Incentives	TIM= 30.9%	TIM = 30.9% between networks =£4.64m /2	
Revenue	Fast: £17.1m TIM: £3.09m TOTAL: £19.19m (minus dev funding)	Transmission Fast = £0 50% Share of TIM (agreed on a case by case basis) = £2.32m TOTAL = £0.81m (minus dev funding)	Distribution Fast = £16.2 50% Share of TIM (agreed on a case by case basis) = £2.32m TOTAL = £17.52m (minus dev funding)
RAV addition	£72.9m	£0	£68.9m
Consumer Saving	£6.91m	-	£9.15
Annual Revenue	Slow: x%* £72.9m (45years)	£0	Slow: x% £68.9 (45 years)

The table above highlights the 'winners and losers' culture that would arise through the CAM mechanism which will act as a disincentive to whole system development.

Overall if the coordinated adjustment is to lead to better outcomes for consumers, it is important that incentives are appropriately balanced between TOs.

In the example above, if the TO were to identify and progress a whole system alternative to the baseline position, it would have to accept that it is willing to forego £19.19m in revenue and £72.19 RAV additions and accept a revenue increase of less than £1m to deliver £2.21m of additional consumer benefit.

Encouraging behavioural change though financial incentives

In the ordinary course of business, the incentive for all operators is to deliver solutions that will minimise cost to the consumer but add value to their own RAV. It is therefore difficult to see the attraction of a mechanism that will ultimately erode agreed additions to that asset base, without any reward to encourage the necessary changes in behaviour. Regulatory precedent demonstrates that introduction of a financial incentive has a strong success rate in achieving a step-change in behaviour. This is demonstrated through SHE Transmission's (and other Transmission Owners) performance across several incentive mechanisms under RIIO-T1, such as improvements in the overall network reliability under the Energy Not Supplied (ENS) incentive. In addition, the use of incentives has seen a reduction in the leakage rate of sulphur hexafluoride (under the SF6 incentive) and a vast improvement in stakeholder engagement as the Stakeholder Engagement Incentive drives network companies to engage effectively with stakeholders to inform how they plan and run their businesses.

We continue to believe that an incentive mechanism linked to the **potential consumer benefit** of transferring allowances will create a stronger incentive mechanism for networks to use the CAM (i.e. networks sharing in the additional benefit realised via a whole system solution). We note that Ofgem provisionally considers this approach to be part of normal Business Planning and project delivery which should, in theory, result in whole system solutions. However, the commercial risk of failing to agree an appropriate compensatory value could **stagnate development of solutions** under a CAM.

Under the CAM proposal Ofgem has suggested that it will be for both parties to agree what the appropriate share should be. Ofgem should revisit this position, to clarify at a minimum that the share of TIM should be skewed towards the party that foregoes RAV.

An agreed adjustment to the sharing factor under the CAM that rewarded the party that foregoes RAV would go some way to incentivise the right behaviour without eroding the overall benefit to consumers.

In addition to certainty, the incentive must be strong enough to elicit the correct behaviour from network companies, otherwise the cost of seeking whole system solutions **will be deemed too expensive** (particularly when taking in to account the potential **RAV reduction**). In addition, a strong incentive for licensees to seek whole system solutions that deliver overall benefits for consumers (as opposed to the value of a project) addresses licensees' concern that investment and effort in seeking a whole system solution is **not appropriately funded**. The potential benefit associated with a strong sharing factor would outweigh the lack of funding (assuming the transfer under CAM is successful).

If certainty was provided as to the potential benefits associated with the CAM, together with sufficient financial incentive, we believe this would – to the benefit of consumers - drive the behaviours Ofgem is seeking in order to develop whole system solutions.

We set out below, a proposal that would ensure that all stakeholders are sufficiently incentivised to the benefit of consumers.

Consumer-led whole System solutions proposal

The bespoke CAM incentive mechanism should only apply to the **consumer value achieved** as a result of identifying a whole system solution. The cost of the original solution compared to the cost of a whole system approach could be shared between consumers and participating networks. Assuming a 50% sharing factor, 50% of the total consumer benefit would be returned to consumers and the remaining **50% split between the participating networks**.

The consumer benefit could be calculated using the original capital cost of delivering the scheme by a sole network licensee as the counterfactual compared to the whole system approach. The difference of cost between the two solutions would provide the **consumer benefit**. This approach also encourages collaboration and equal levels of participation across networks. The value of consumer benefit delivered and how this is calculated should be the subject of further development with networks. One potential approach towards measuring consumer benefit is currently being developed under the ENA's Open Networks project Workstream 4, Product 1 **('Whole System CBA'**). This would provide the basis upon which to determine the potential benefit to consumers as a result of transferring outputs.

The party then assigned as responsible for delivering and constructing the whole system solution will continue to be **subject to the RIIO-2 totex incentive mechanism as per its RIIO-2 Business Plan Assessment**. Any efficiencies gained during construction, operations etc are shared as per that networks **totex incentive sharing factor**. Ensuring that any savings are shared between the network company and consumer.

***Core Question 14**: Do you consider that two application windows, or annual application windows, are more appropriate, and should these be in January or May?*

We remain concerned at the proposal to include windows. The process associated with the transfer of existing outputs must not impact on or add unnecessary delay to connections infrastructure (with contracted connection dates). We consider the Co-ordinated Adjustment Mechanism should be useable on an 'as required' basis. If proposals are subjected to a four-month decision window this could deter networks from seeking potential whole system opportunities. We would welcome further detail from Ofgem as to how it intends to mitigate the impact of re-opener windows on the development of connections infrastructure.

***Core Question 15**: Do you consider that the RIIO-1 electricity distribution licences should be amended to include the CAM, or wait until in 2023 at the start of their next price control?*

Yes. It is our view that for the CAM to work effectively, all parties involved should be able to act as the 'lead'. We acknowledge this may cause some disruption prior to the development of ED2 licences. However, if licences are not amended, the TO's will be the only party with the ability to lead engagement prior to 2023. This is due to the obligation to explore whole system opportunities under the whole system licence condition. This approach could create unnecessary cost and disruption for TO's – particularly where the outcome of the CAM would result in allowances being transferred from TO to DNO.

***Core Question 16**: Do you agree with our proposed re-opener windows for cyber resilience OT and IT, and our proposal to require all licensees to provide an updated Cyber Resilience OT and IT Plan at the beginning of RIIO-2?*

We agree with the proposed re-opener windows for cyber resilience OT and IT, and Ofgem's proposal to require all licensees to provide an updated Cyber Resilience OT and IT Plan at the beginning of RIIO-2.

The cyber resilience environment is fast changing as existing threats develop and new risks and threats emerge. We believe that the opportunity to submit updated cyber resilience OT and IT plans during the first re-opener window at the start of RIIO-2 and the proposed mid period re-opener window will assist in mitigating the impact of the changing threat landscape.

No supplementary question was raised on this issue following submission of the Business Plan.

We are disappointed that was a lack of engagement during the Supplementary Question process on the IT cyber plan which has resulted in an accepted need with no current allowance.

***Core Question 17**: What are your views on including the delivery of outputs such as: CAF outcome improvement; risk reduction; and cyber maturity improvement, along with projects-specific outputs?*

No supplementary question was raised on this issue following submission of the Business Plan, however, we welcome the opportunity to demonstrate the effectiveness of the Cyber Resilience IT Security measures identified in the RIIO T2 Cyber Security IT Plan (T2BP-PAP-0003). We have existing key performance indicators to manage and report our security posture and we would be keen to ensure that these align with any alternative proposals put forward by Ofgem. Due to the inherent difficulties in assessing these measures, we would like to engage closely with Ofgem, and other TOs as necessary, to ensure that the assessment of output measures is both effective and efficient.

***Core Question 18**: Do you agree with our proposal for the Non-operational IT and Telecoms capex re-opener?*

Yes, we agree with Ofgem's proposal for the Non-operational IT and Telecoms capex re-opener. We support the two re-opener windows, as well as the re-opener having no materiality threshold and not being subject to the materiality aggregation (i.e. excluded from the common re-opener principles noted on page 60 of the RIIO-2 Draft determinations Core Document).

No supplementary question was raised on this issue following submission of the Business Plan, however, we seek further guidance on the application process and assessment timescales and will work with Ofgem to develop the settlement.

***Core Question 19**: Do you agree with our approach to using a re-opener mechanism for changes to government physical security policy?*

We agree with Ofgem's approach in using a re-opener mechanism to adjust allowances for changes to Government physical security policy. We support the proposal to have a re-opener windows at the mid-period and at close out. We seek clarity on why this midperiod re-opener is in 2023 which does not align with the other 2024 re-opener windows.

However, we disagree that the materiality threshold should follow the common re-opener approach (see Core Q12). Given that government policy and revisions to the CNI list are out of network companies' control and that the expenditure required to deliver activities is to protect critical national infrastructure, we believe network companies' should not be expected to carry additional risk exposure in this area through a materiality threshold. We propose that a similar approach to the cyber resilience IT and OT re-opener is used, where there is no materiality threshold on the basis that "*Cyber resilience OT and IT activities are carried out to reduce and mitigate threats relation to national security*" and that "*therefore* [Ofgem] *do not think it is appropriate that projects must meet a materiality threshold*." It is unclear why Ofgem has drawn a distinction for physical site security since, like cyber resilience, physical site security activities are carried out to reduce and mitigate threats relating to national security. We also don't believe that there will be significant regulatory burden in assessing and reviewing submissions relating to physical security and this supports our position to have no materiality threshold.

No supplementary question was raised on this issue following submission of the Business Plan, however, we seek further guidance on the application process and assessment timescales and will work with Ofgem to develop these.

***Core Question 20**: Do you agree with our approach regarding legislation, policy and standards?*

No. We disagree with Ofgem's approach not to introduce an additional uncertainty mechanism to adjust allowances in response to some changes in legislation, policy or technical standards. Specifically:

- While we did not classify them as "legislative, policy or technical standards" in our Business Plan, we disagree that there are no re-openers for to **Landowner Compensation** and **Brexit Import Charges** and suggest that these both should be subject to a **logging up mechanism** (see below and our appendix T2BP-DD-SHE-010 "True up, Logging Up and Re-openers: SHE Transmission RIIO-T2 Proposals").
- We believe there should be a "Legislative, Policy and Standards" reopener comprising:
    - Energy Code Review, Significant Code Review, Transmission Owner Code (STC) Operational Load Management Schemes;
    - Access Reform & Significant Code Review;
    - Environment and Climate Change;
    - HSE's Electricity Safety, Quality and Continuity Regulations (ESQCR).

The table below sets out how Ofgem addresses our Business Plan proposal for a re-opener covering developments in legislation, policy and standards (which we referred to as legislative, policy or engineering standards), along with our proposed separate re-openers for flood resilience, landowner compensation and Brexit import changes. For completeness, there are additional areas that we did not seek re-openers for but Ofgem is seeking views (access reform, environment & climate changes and environmental enhancement).

There is no doubt that the energy industry is transitioning through unprecedented change, and while energy policy changes are anticipated over RIIO-T2, there is uncertainty surrounding a number of areas which could have a material impact on our expenditure throughout RIIO-T2 which is out with our control. We accept that Ofgem has accounted for potential legislative and policy changes through other uncertainty mechanisms (namely the MSIP), but there are still areas which need to be considered. The areas marked red in the table – landowner compensation and Brexit import charges - are of particular concern. We are also concerned with the exclusion of the code reviews from any re-openers. All of these are considered below.

Core Q20 Table 1 – summary of response to proposed additional uncertainty mechanisms

SHET Proposal	Ofgem DD	SHET position on Ofgem DD
Landowner compensation	No re-opener but seeking views	**Strongly disagree** – landowner compensation should have an end of period symmetrical logging-up on costs (with no materiality) provided Ofgem provide baseline allowances. See below and appendix "T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals"
Brexit Import Charges	No re-opener but seeking views	**Strongly disagree** – Brexit should have a separate logging up mechanism in period and end of period (with no materiality). See below and appendix T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals"
Legislative, Policy or engineering standards: Security and Quality of Supply Standard (SQSS)	Part of the MSIP re-opener	Accept as part of MSIP. See response to ET Q13
Legislative, Policy or engineering standards: Energy Data Taskforce data requirements (BEIS)	Part of the MSIP re-opener	Accept as part of MSIP. See response to ET Q13
Flooding	Part of the MSIP re-opener	Accept as part of MSIP, but with additions as below and response to ET Q13
Legislative, Policy or engineering standards: Energy Code Review, Significant Code Review, Transmission Owner Code (STC)	No re-opener but seeking views	Disagree. Should include as part of wider "Legislative, Policy and Standards Re-opener". See below.
Access Reform & Significant Code Review	No re-opener but seeking views	Disagree. Should include as part of wider "Legislative, Policy and Standards Re-opener". See below.
Environment and Climate Change	No re-opener but seeking views	Disagree. Should include as part of wider "Legislative, Policy and Standards Re-opener". See below.
Legislative, Policy or engineering standards: HSE's Electricity Safety, Quality and Continuity Regulations (ESQCR)	No re-opener but seeking views on "engineering technical standards"	Disagree. Should include as part of wider "Legislative, Policy and Standards Re-opener". See below.
Environmental enhancement	No re-opener but seeking views	No views on this.

Landowner Compensation & Wayleave Review Adjustment (baseline and logging up)

Ofgem has rejected our proposed Landowner Compensation re-opener that would provide appropriate allowances to ensure we have adequate and robust land rights in place (i.e. which deal with Injurious Affection and compensation claims) in order to operate and maintain a safe, secure and resilient network throughout our licence area.

We are currently seeking both a baseline allowance and an uncertainty mechanism comprising an end of period true-up. Our RIIO-T2 baseline forecast is our best estimate, following extensive assessment of the RIIO-T1 period and an understanding of our existing cases and the likely termination and claims landscape over the next five years. But we understand that while we can take action to manage the risk of claims, this is an area of costs that is driven by third parties (the courts) and is largely outside our control. In recognition of this we believe our proposals are justified to protect both company and consumer. We are not seeking to outperform in this area, rather to recover our efficiently incurred costs. Ofgem removing the re-opener makes no sense. It places significant risk on the licensee without any consumer benefit as the final costs will be subject to a true-up under our proposals.

Following discussions with Ofgem after the submission of our Business Plan (and prior to Draft Determinations) we altered our Business Plan approach from solely a re-opener, to a baseline plus an end of period true-up. This change on our approach was based on two things: 1. confidence in our bottom-up costings and 2. Alignment with the other TOs which Ofgem sought as much as possible across all UMs.

However, it is important to note, as of Draft Determination stage, we currently do not have a confirmed baseline allowance nor an uncertainty mechanism to recover the costs for injurious affection claims, which is a significant concern. We have provided Ofgem with a justification paper setting out the level of ex ante allowance required and highlighted the requirement for an end of period true-up mechanism to protect both licensee and consumers.

We believe an end of period true-up is clearly justified as these costs are subject to change which is largely outside our control. Our RIIO-T2 forecast is our best estimate, following extensive assessment of the RIIO-T1 period, an understanding of our existing cases and the likely termination and claims landscape over the next five years. However, significant unforeseen claims may become apparent as we develop our network through the RIIO-T2 period. We have managed the risks where we can, but this is an area that is solely driven by claimants and the Courts and is largely outside our control.

Injurious Affection claims are a legal matter and it should be acknowledged that court decisions and consequential levels of compensation directly awarded, or influenced on a settlement basis following court proceedings, carry a degree of uncertainty which may lead to fluctuation from our RIIO-T2 forecast. These fluctuations in costs are completely outside our control as they are directed by the courts. Ofgem has not provided any justification for the rejection of the re-opener, other than we have a baseline allowance (not yet approved) and we can manage our risks within this allowance. This is not the case. Therefore, we strongly believe that injurious affection claims are an uncertain cost which require an end of period true-up to ensure that both the networks and consumers are protected.

In addition to this, as set out in our Business Plan, there has been a recent review of Wayleave Compensation Rates implemented in England and Wales in order to ensure farmers are receiving an accurate payment to cover the cost of the interference caused by poles and pylons in fields. This has given rise to a similar review which is now taking place in Scotland where rates have not been updated since April 2013. This could potentially lead to additional claims and/or increased payments. The outcome of this review is being driven by third parties which again is outside our control. Based on the SHE Transmission's annual wayleave expenditure this would result in a £0.5m increase across RIIO-T2 if there was an increase of 20%. However, given that this review is ongoing, and the final adjustment is uncertain, we are unable to accurately forecast the potential adjustment to wayleave costs.

To avoid regulatory burden, if and only if, Ofgem approve our baseline, we suggest no mid-period re-opener but a logging up of expenditure and ex post adjustment. Provided we demonstrate we have taken all reasonable steps to mitigate costs (similar to the approach with business rates) then we log up our costs. At close out (accounted for 2026/27) whatever baseline allowances we don't spend is returned in full to customers and any additional spend is recovered. No materiality applies. This Is detailed in our "T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals" Appendix.

Brexit (logging up)

There is still significant uncertainty around the timing and impact that Brexit will have on the UK. Covid-19 has added to this uncertainty, as negotiations regarding future trade agreements have been put on hold. This increases the risks that the UK will leave with a no deal. The impact on network companies' costs will be very difficult to predict until clarity on the import tariffs and VAT rates is provided. Our supply chain for assets is largely in Europe and therefore any changes to VAT and import tariffs could be significant.

The VAT rate on transformers and circuit breakers is currently 20% and that is unlikely to change through the legislative changes due to Brexit. However, the area that is most likely to effected by Brexit will be the change in import tariffs. For imports from EU countries there is currently no import tariff. The current import tariff for Non-EU countries is ~3% for transformers and ~2% for circuit breakers and if this was applied to the assets that we procured from Europe over RIIO-T1, it would amount to a material increase in the costs of assets. This increase is outside the control of SHE Transmission and unlike other unregulated industries we are unable to efficiently respond to these cost changes due to changes to legislation. We strongly believe that this is a significant area of risk for both networks and consumers and Ofgem need to acknowledge that a level of flexibility is required around the scope of a Brexit re-opener.

We suggest that where tariffs are changed, there is a logging up of the cost impacts with an adjustment in 2023/24 (for first two years) and end of period in 2026/27 (for years 3-5). No materiality applies. This Is detailed in our "T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals" Appendix.

Flooding, Wildfires & Extreme Weather

We provide below further justification on our proposal to expand the Flood Resilience component within the MSIP re-opener to include Wildfires, and Extreme Weather and Multi-Hazards (e.g. a combination of drought, high rainfall and high temperatures) as we see these are credible threats to our network in RIIO-T2. The CCC have identified climate adaptation as a priority action, planning for a minimum 2°C and consideration of a 4°C global temperature rise (by 2100 from pre-industrial levels). Despite a temporary reduction in emissions from the Covid crisis, global greenhouse gas emissions are still on a pathway for 3°C or more of warming by 2100. Even under the minimum 2°C scenario, an increase in the frequency and intensity of climate-related hazards, due to a combination of drought, high rainfall and high temperatures, is inevitable. The ENA is actively working to secure the resilience of the energy network, to which aim the ENA has created the industry-wide Adaptation to Climate Change Working Group to better report on and respond to climate change.

As climate science and policy develops we will continue to improve our understanding of the impacts of climate change on our network. However, the needs case and costs for asset resilience works associated with climate adaptation are highly uncertain in both the short and longer term and are tied to the overall uncertainty around global decarbonisation pathways. Without a mechanism to account for the costs of these potential works, there is a risk that we could fail to deliver assets resilient to the impacts of climate change, with attendant impacts on our network safety and reliability. As we cannot yet estimate what the financial impact of climate adaption would be, we propose that the MSIP re-opener mechanism should be expanded beyond flooding to also encompass wildfires, other extreme weather events and multi-hazards related to the impacts of climate change. We believe this is in line with Ofgem's statutory duty in relation to climate change.

Legislative, Policy and Standards Re-opener

We suggest a Legislative, Policy and Standards Re-opener with a window in January 2024 and one at close out, with a materiality threshold equivalent to the regulatory burden for undertaking the review. If the value in question (i.e. over or underspend) exceeds the value of the regulatory burden of undertaking the re-opener then it reasonably follows that it should be triggered. If not, it shouldn't be triggered. We do not believe that a proportion of base revenue is an appropriate trigger threshold. Instead the trigger should be a fixed absolute value. We suggest this be set at c£1m-£2m.

We suggest that this re-opener comprises the following:

- **Access Reform Implementation & Significant Code Reviews:** While the majority of changes following the Access Reform will impact Distribution networks, we may see an increase in Distributed Generation (DG) connecting directly to the transmission network as a result. We believe that existing mechanisms within the RIIO-T2 price control will accommodate this, such as the volume driver mechanism. However, given the uncertainty in the potential scale of implementation costs in other areas such as interfaces between transmission and distribution, such as increased IT resource and data processing, we believe that this should be included in a legislative and policy re-opener. These are costs that are unforeseen, out with our control and could be substantial through implementing the Access Reform.

  We also believe that there is uncertainty around the potentially significant impacts of unforeseen code changes driven in general by the Significant Code Review (SCR) mechanism. The SCR mechanism is designed to facilitate complex and significant changes to the codes that energy companies are required to abide by. These changes may have substantial financial implications on network companies in implementing and abiding by these code changes that are out with their control. Therefore, we believe that to ensure that code changes through the SCR are implemented economically and efficiently, a re-opener mechanism is needed. We suggest that this is part of the SCR implementation process and licensees are allowed to seek additional baseline allowances for associated costs. These are subject to the TIM like any other baseline costs. This is a simple regulatory protection at no cost to the consumer which will allow for the delivery of consumer benefits through code changes.

- **Environment and Climate Change:** It is currently unknown what Government Policy will be implemented over the RIIO-2 period to accommodate legislative amendments as a result of the CCC's recent recommendations. The Scottish Government have passed legislation relating to Scotland achieving net zero GHG emissions by 2045. Ofgem has to accept that given the significant uncertainty surrounding the potential scale and timing of unforeseen legislative amendments and policy, it is not possible to fully define the scope of the legislative changes that should be included within the re-opener mechanism.

  There is no risk for Ofgem to include a re-opener mechanism for legislative/policy changes, it is within its gift to reject re-opener submissions it feels are not appropriate. However, there is a significant risk if there is not the mechanism for Ofgem to provide responsive and flexible regulation to mitigate the risks to existing and future infrastructure, driven by legislative amendments that are out with the control of the TOs.

- **HSE's Electricity Safety, Quality and Continuity Regulations (ESQCR)**: It is currently unknown what changes to the Electricity Safety, Quality and Continuity Regulations (ESQCR) may be made during RIIO-T2, if any. However, we believe that amendments to this legislation which are out with our control, have a significant impact on existing or future infrastructure and have a substantial financial risk, which should not be carried by the networks. For example, changes to the minimum height of Overhead Lines could have a significant impact on our network. These costs should be subject to a legislative and policy re-opener as this is a simple regulatory protection at no cost to the consumer which will allow for the recovery of efficient costs incurred due to legislative amendments. We suggest that, similar the SCR above, the have to align with the process of the ESQCR changes, and licensees are allowed to seek additional baseline allowances for associated costs. These are subject to the TIM like any other baseline costs. This is a simple regulatory protection at no cost to the consumer which will allow for the delivery of core safety regulations.

***Core Question 21**: Do you agree with our overall approach to meeting Net Zero at lowest cost to consumers? Specifically, do you agree with our approach to fund known and justified Net Zero investment needs in the baseline, and to use uncertainty mechanisms to provide funding in-period for Net Zero investment when the need becomes clearer?*

Net zero greenhouse gas (GHG) emissions are legislated national policy targets. We agree that the action taken in the energy sector should consider the cost to consumers of different options to meet the targets. In doing so, such analysis should assess the whole life of options, the full range of socio, economic and environmental impacts, and the likelihood that the energy sector will be required to be a net extractor of GHG emissions.

In the context of these Draft Determinations for electricity transmission, licensees' actions contribute to the achievement of net zero GHG emissions in two ways: (i) through timely, cost effective facilitation of the energy transition towards renewable electricity sources, and (ii) by acting to reduce direct (scope 1 and 2) and indirect (scope 3) emissions from business operations. Each licensee set out detailed proposals on both areas in their Business Plans utilising both baseline funding and uncertainty mechanisms to protect consumers' interests.

The Draft Determinations do not explicitly set out how the proposed adjustments to licensees' Business Plans result in better alignment with the achievement of net zero targets. In our opinion, when taken in the round, the Draft Determinations are a barrier to progress towards net zero targets and will increase costs to consumers over the long term.

For SHE Transmission, our key concerns with Ofgem's proposed application of its approach to meeting net zero targets are as follows:

Errors and methodological flaws in the setting of the baseline allowance

These are explained in detail elsewhere in our response. Baseline funding largely covers maintenance and operation of the existing infrastructure, along with customer service and other day-to-day business operations. There is no evidence that consumers will accept a diminution in the quality of these activities as the industry decarbonises. A regulatory determination that makes it extremely challenging to maintain baseline activities will have a knock-on effect on licensees' focus, innovation and capability to go above-and-beyond, including investing for net zero.

Assessment of net zero pathways

In order to be able to assess the effectiveness of regulatory policy, it is necessary to have a defined goal. For the achievement of net zero targets, that goal should be whether the policy can accommodate the credible net zero pathways within the RIIO-T2 period (and beyond). We see no evidence that Ofgem has undertaken such an assessment.

For SHE Transmission, we clearly set out (following lengthy and detailed consultation with stakeholders) our view of credible net zero pathways for the north of Scotland. We overlaid the baseline funding in our Business Plan, and how we proposed uncertainty mechanisms would work to 'close the gap' between the baseline and net zero. As current net exporter of renewable energy, with a modelled expectation that the volume of export would increase to achieve net zero, we used connected generation to illustrate net zero pathways. Under baseline funding then 11.2 GW of generation would be connected by the end of RIIO-T2, we anticipated a Likely Outturn of 13.6

GW at the bottom end of our net zero pathways. Separately, we analysed and set targets for our own business emissions aligned with a 1.5 degree warming pathway.

Despite requiring licensees to set out detailed analysis and modelling of future energy scenarios in their Business Plans, we see no commensurate analysis in the Draft Determination of either licensees' scenarios or Ofgem's own scenarios of net zero requirements from the electricity sector. Accordingly, in the absence of presenting such analysis, there is no further analysis as to how the proposed regulatory policy is designed to ensure those pathways can be achieved.

Errors and methodological flaws in the design of uncertainty mechanisms

We agree in principle with the use of uncertainty mechanisms during the price control period as a means of responding to unforeseeable developments, provided that such uncertainty mechanisms are only employed in relation to developments that are genuinely unforeseeable, that there is "*clarity between all parties around the processes for recovering these costs*[13]" and that applications are resolved in a sufficiently timely manner. This is the "Certain View" approach on which our RIIO-T2 Business Plan was based. It was also the approach established, adopted and tested in anger by SHE Transmission in RIIO-T1 and why we proposed continuation with it in RIIO-T2.

Unfortunately, however, the uncertainty mechanisms proposed in the Draft Determinations: (i) would leave too many aspects to be resolved; (ii) lack procedural clarity; and (iii) would take too long to resolve. The combined effect of the proposed uncertainty mechanisms would therefore be to dampen Net Zero; an area of greatest concern in and which will have long-term detrimental consequences for the GB consumer and society. Net Zero will not be achieved.

We would therefore particularly welcome ongoing engagement with Ofgem on remedying these issues as it is vital that these mechanisms work as intended.

The key mechanisms relevant to achieving Net Zero are:

- pre-construction (baseline and the UM);
- volume driver for demand and generation connections;
- Medium Size Investment Projects (MSIP); and
- Large Onshore Transmission Investment (LOTI).

Again, these are explained in detail elsewhere in our response.

Two of these – the Volume Driver and LOTI – build on existing, and successful RIIO-T1 uncertainty mechanisms. The third – MSIP – seeks to close an agreed 'gap' in the regulatory framework for investments of <£100 million, including those triggered by third parties[14].

It is critical that these mechanisms operate effectively, i.e. once certainty is confirmed, licensees are funded to take timely, efficient action to address the need. In the development of our Business Plan, this was a key concern for stakeholders – while there was strong support for uncertainty

[13] CMA SONI Final Determination, para. 6.45.
[14] SHE Transmission proposed two tailored mechanisms in our Business Plan to address this gap, pages 80-81 of our Business Plan https://www.ssen-transmission.co.uk/riio-t2-plan/

mechanisms, this was caveated by a concern that such mechanisms did not introduce cost, uncertainty and delay to achieving net zero targets.

We not believe that the Volume Driver, MSIP and LOTI as set out in the Draft Determinations are optimally designed to achieve net zero targets. We have two main concerns.

First, for the Volume Driver, the input data, modelling and construct of the mechanism are flawed, resulting in a mechanism that poorly aligns allowances with expenditure.

Second, for the MSIP and LOTI, the timing and regulatory process for these mechanisms is not aligned with network users' needs, resulting in increased costs and delay to critical investments.

Assessment of the application of uncertainty mechanisms

Will the proposed uncertainty mechanisms work? This is not considered in the Draft Determinations. We note that Ofgem proposes to issue guidance on the MSIP and LOTI mechanisms at a later date and, accordingly, our ability to assess workability of these mechanisms in advance of that guidance is limited. In any event, however, we have procedural concerns based on the initial proposals set out in the Draft Determinations.

The key drivers for renewable generation in the north of Scotland are likely to be the outcome of the next Contract for Difference (CfD) auction round and the outcome of the ScotWind leasing. These give a clear and certain signal as to when investment will be required. There is a credible pipeline of up to 2.5 GW of eligible generation developments, including on remote Scottish Islands, that might participate in the CfD round for connection forecast to be 2025/26 and 2026/27. Successful generators will reasonably expect SHE Transmission to deliver connections (and associated infrastructure) on time, and for the regulatory framework to enable that. Construction works should commence in late 2021 and 2022 (with pre-construction in advance of that). Neither the MSIP nor the LOTI mechanisms is designed with timely CfD connections as the driver, for example, by aligning regulatory approvals for investment with the certainty of the CfD auction result. The MSIP application window is January 2024 and the LOTI assessment period is up to 30 months. Ofgem's uncertainty mechanism proposals would require SHE Transmission to spend £100s million at risk. Uncertainty about future regulatory approval for expenditure will naturally make licensees more cautious about being innovative or proactive in these activities, thereby hindering their ability to meet the net zero targets.

The Scottish Government forecasts 8-10 GW of offshore wind connections in the late 2020's. This would double the existing generation connected to the north of Scotland network and so require significant strategic investment. Strategic investment in electricity transmission can take ten years to develop, design, assess options, engage with stakeholders and build. Many studies have shown that comprehensive and thorough pre-construction is essential to ensure timely, cost effective delivery. This is SHE Transmission's experience based on our track record of capital investment delivered on time and under budget, such as our £1bn Caithness-Moray HVDC subsea cable energised in 2019 which proved up to 1,200MW of capacity to transmit power from renewable energy sources from across the far north of Scotland. It is also a strong area of feedback from our stakeholders, who consistently expressed a desire to be engaged early and participate in the co-creation of infrastructure so as to manage the impact on their communities and environment. It is of concern, therefore, that the Draft Determinations does not propose baseline funding for this certain need for pre-construction and instead suggests that this expenditure be subject to an ex-post review in 2026/27. Such a regulatory approach is contradictory to baseline funding for known need and introduces caution on the part of the licensee in the knowledge that any monies spent might not be allowed.

Mixed messages on own business emissions' targets

The minimum requirements for RIIO-T2 specified the setting of a science-based target aligned with the 2 degree warming pathway. SHE Transmission is the first global network to have its 1.5 degree warming target accredited by the Science Based Target Initiative (SBTi). However, this ambition – motivated in large part by the strong views of our stakeholders – has not been acknowledged in the Draft Determinations. First, although the outputs in our Sustainability Action Plan have been accepted, the associated funding has been disallowed. Second, the evidence presented to substantiate and quantify our ambition (including independent benchmarking) has been disregarded in Ofgem's decision on the Consumer Value Proposition and Business Plan Incentive.

Overall, and in particular when compared with the evidence-based, stakeholder-led and rigorously modelled proposals in our Business Plan, we cannot conclude that the Draft Determinations have the achievement of net zero GHG emissions targets at its heart. As we consider in detail elsewhere in our response, data and modelling errors are mechanistic and should be easily resolved for Final Determinations. More fundamentally, we urge Ofgem to re-assess: (i) its approach to pre-construction funding and recognise the criticality of this investment for timely, cost effective investment; and (ii) the design of the critical uncertainty mechanisms (Volume Driver, MSIP and LOTI) to align with forecast network need. Net zero targets are fixed policy. Delays to action during the RIIO-T2 period will come at a cost to future consumers.

***Core Question 22**: Do you think the package of cross sector and sector-specific UMs provides the appropriate balance to ensure there is sufficient flexibility and coverage to facilitate the potential need for additional Net Zero funding during RIIO-2?*

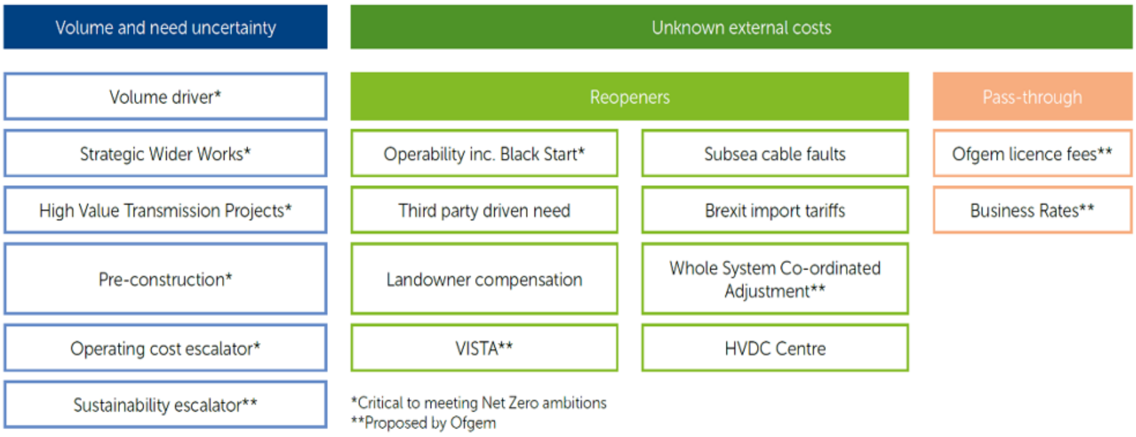
No, we don't think the package of cross sector and sector-specific UMs provides the appropriate balance to ensure there is sufficient flexibility and coverage to facilitate the potential need for additional Net Zero funding during RIIO-2. Specifically, we highlight:

- Insufficient upfront funding and ex-post appraisal risk for essential pre-construction to undertake options assessment, engage stakeholder and prepare high quality UM submissions
- Modelling errors in the design of the mechanisms, e.g. the Volume Driver
- Misalignment of UM timing with system users' needs, e.g. the MSIP and CfD AR4
- Lengthy regulatory assessment processes that give no certainty to system users or the supply chain, e.g. LOTI
- Significant ex-post regulatory interventions that dampen appetite for innovation, agility and realising efficiency, e.g. MSIP and LOTI
- No impact assessment that maps proposed UM application to possible net zero pathways during the period up to 2030.

The intention is there, but the design and proposed execution of the UMs is flawed meaning they will act as barriers not facilitators to releasing sufficient and timely allowances for Net Zero.

We set out our proposal of UMs in Figure 5.1 on Page 80 of our Business Plan and within the Business Plan supporting document *Regulatory Framework: Uncertainty Mechanisms*. In doing so, we noted clearly which were critical to meeting Net Zero ambitions by marking with an asterisk (see the Figure below). The key mechanisms are:

- Volume Driver for generation and demand connections;
- Strategic Wider Works (Ofgem renamed LOTI)
- High Value Transmission Projects (Ofgem renamed Medium Sized Investment Projects (MSIP))
- Pre-construction;
- Operating Cost Escalator; and
- Operability including Black Start escalator.



As stated, while Ofgem has allowed them in name (albeit a different name in some cases), we are concerned with the proposed design and execution of the first four mechanisms above and we clearly set out the reasons for this in the relevant questions and a supplementary paper for the volume driver.

The changes we propose to Draft Determinations are simple and entirely justifiable, and in making them we believe the execution of the mechanisms can reach the Net Zero ambition they are intended for:

- The volume driver is based on modelling errors that must be fixed.
- For net zero we expect >£4 billion of MSIP and LOTI submissions (see our response to Core Q21) and therefore decisions must be timely.
- Pre-construction funding is essential to efficient investment and therefore must be allowed within our baseline and during the period as required.

The response to this question will not repeat the detail contained in the response for each of the mechanisms; rather in this response we summarise the key simple changes that need to be made and refer to the relevant question in the table below.

Mechanism	Ofgem proposal	SHET proposal	Consequences	Question/Doc reference
Volume Driver	Automatic adjustment based on pre-set unit cost allowances (UCAs) that are significantly below the cost of the work required to build the connection infrastructure.	Either correct errors to Ofgem Model for cost reflective UCAs or adopt our proposed model which provides cost reflective UCAs.	SHET will not be able to recover the costs, let alone find efficiencies in an incentive framework for an area significant investment. Volume driven connections are estimated to c£0.5bn.	Core Q22 Uncertainty Mechanisms - Generation and Demand Volume Driver Main document Chapter 4
LOTI (previously SWW)	24-30 month binary approval process for all projects	Reduce timescales and commit to a 6-month decision. Adapt the process to	Projects are unnecessarily delayed. As an example, just one	Core Q22, ET Q12

		ensure it is fit for purpose for all projects – NOA driven schemes, connection driven projects, CfD auctions etc.	project, our Skye reinforcement project, will be delayed for at best between 6-12 months. Compounding that across many is considerable.	Main document Chapter 4
MSIP (SHE T proposal HVTP)	One window in January 2024 for projects £25m-£100m that cost double the UCAs provided under the volume driver	Remove window for "as required" basis and set materiality to reasonable level based on an appropriate volume driver.	Failure to do so makes this mechanism redundant. TOs would have to carry significant financial risk to take forward MSIP projects, or alternatively, trigger delays until funding has been secured.	Core Q12, Core Q22, ET Q13 Main document Chapter 4
Pre-Construction	To disallow £102m (£89m for large strategic schemes and £13m for T3 non-load schemes) of our baseline funding and to assess any pre-construction expenditure as part of close-out	Reconsider our baseline ask (see our Pre-construction funding paper). These large strategic schemes to be subject to end of period true-up. Small load and non-load T3 schemes to a logging up. Plus, in-period mechanisms for new large strategic schemes not part of our baseline ask.	TOs would have to carry significant financial risk on pre-construction or when projects fail to progress due to factors outside our control.	Core Q 22, ETQ Q10 and Q11 Pre-construction Funding Paper Main document Chapter 4

***Core Question 23**: Do you have any views on our proposed approach to a Net Zero re-opener?*

As outlined in our 22 May 20 response to Ofgem's 5 May open letter, we support the introduction of the Net Zero re-opener in principle but under the following conditions:

- It is used only where other uncertainty mechanisms designed as part of the RIIO-T2 settlement cannot facilitate the changes required to achieve net zero;
- It is an upside uncertainty mechanism only, based on the evidence of investment plans presented and the regulatory mechanisms already in place to protect consumers;
- It can be triggered as/when required; and
- Licensees can trigger the re-opener.

We therefore welcome the following elements of Ofgem's Net Zero re-opener proposal:

1. The re-opener can be triggered at any time throughout the RIIO-2 price control
2. The re-opener is limited to changes connected to the achievement of the Net Zero carbon target not otherwise captured by any other RIIO-2 mechanism

We disagree with the following elements of the proposal:

1. The re-opener could result in decreases in allowed revenue or adjustments to existing output targets

As per our 22 May response, we disagree that the re-opener should enable a decrease in baseline allowances. We see no circumstance which would require us to deliver less than our Certain View to put us on the trajectory to achieve net zero and as such we don't think it will be necessary for Ofgem to adjust allowances downwards, particularly with the existence of price control deliverables (PCDs), our own output delivery commitment and Enhanced Reporting Framework, all of which will ensure delivery of outputs or materially equivalent outputs. More so, Ofgem has proposed specific 'true up' provision within the RIIO-T2 Draft Determinations (which we respond to elsewhere), so an additional 'blanket' provision is unnecessary. There should certainly not be the situation where Ofgem can unexpectedly decide to revisit previously agreed outputs and expenditure.

Therefore, we propose that the re-opener be limited to new additional outputs; and an upwards trigger only. Similar to the RIIO-T1 SWW mechanism, we would anticipate that the re-opener and relevant licence changes would be project specific and in relation to any new project-specific outputs associated with additional revenue. Contrary to the suggestion in the Draft Determination, we do not consider that it would be necessary for Ofgem to consult on nor make any other changes to the licence.

Any decision under the net zero re-opener should be taken in the context of the wider price control settlement. In this regard, we would expect Ofgem to give due consideration to interactions and interdependencies with previously agreed outputs (e.g. the net zero re-opener might be a substitution) and to maintaining the overall financeability of the licensee.

Ofgem has presented no evidence or explanation within its Draft Determinations proposal to demonstrate why any net zero developments would result in a reduction in outputs or associated allowances.

2. Ofgem should have sole ability to initiate the Net Zero re-opener

As per our 22 May response, we disagree that Ofgem should have sole ability to trigger the re-opener. The mechanism must be capable of being triggered by Ofgem or the licensee. Not to allow the licensee to trigger the mechanism will risk opportunities being missed that the licensee is best placed to anticipate and identify. For instance, while Ofgem may be aware of major policy changes, we believe it is the licensee, through ongoing stakeholder engagement, who is best placed to understand the impact of that change on its network and the network intervention required to realise the net zero opportunities. Also, given wider legal and regulatory obligations placed on the licensee, it is essential that licensees have an opportunity to seek adjustments to the regulatory framework as and when they believe they are required.

Ofgem has acknowledged this request but rejected it within its Draft Determinations, noting that it considers it important that the mechanism should only be used in circumstances where it will lead to consumer benefit, which in its view it is "well" placed to make decisions on, although it does not explain why other stakeholders might equally be well placed. We would strongly encourage Ofgem to clarify its approach to assessing that consumer benefit – particularly where the investments are strategic and the benefits will accrue across multiple users.

Given that any submission from a licensee under the re-opener would need to be supported by a CBA, and approval and associated allowances would be assessed by Ofgem on this basis, we disagree that there is any risk posed to consumers if the re-opener is triggered by a licensee and Ofgem does identify any downside to this approach. The use of the ENA-led 'whole system CBA' would promote consistency in decision making and allow all parties to properly assess opportunities that merit further consideration under the net-zero re-opener.

We recognise Ofgem's proposal that it will take input from stakeholders (including licensees) into account when considering whether to trigger the re-opener, which is welcomed, but continue to believe that this alone could result in a slow process and missed opportunities.

We note also Ofgem's proposal that Net Zero Advisory Group (NZAG) may play an important role in assessing when to trigger the Net Zero re-opener. We have previously voiced our support for the introduction of a NZAG to provide increased strategic coordination between Ofgem, Government and key stakeholders. We note the importance of transparency, and specific, evidence-based decision making of this Group if it is to be most effective in ensuring decisions on price control strategic investment are closely co-ordinated with those of policymakers. We believe this could be better achieved if licensees have a role on this Group; a route to present, inform and influence all proposals at the NZAG and any subsequent re-openers.

3. To apply the common materiality threshold applicable to other re-openers

We disagree that the materiality threshold should follow the common re-opener approach (see our response to Core Q12). If the TO is asked to do something that neither it nor Ofgem at this point can define due to of policy, it would be reasonable not to have any re-opener threshold (i.e. set it at 0), a proposal that has been recognised as potentially preferable in this instance. If one is deemed necessary, it must be set low enough so as not to expose the licensee to risk that is outside its control. We propose if the value in question (i.e. underspend) exceeds the value of the regulatory burden of undertaking the collective Net Zero reviews then it reasonably follows that a re-opener should. If not, it shouldn't be triggered. We do not believe that a proportion of base revenue is an appropriate trigger threshold. Instead the trigger should be a fixed absolute value. We suggest this be set at c£1m-£2m for all Net Zero re-openers over the period.

***Core Question 24**: Do you agree with our proposals for the RIIO-2 Strategic Innovation Fund?*

We agree in principle with the direction that development of the Strategic Innovation Fund (SIF) is taking. Supporting a transition to Net Zero and targeting more collaboration across industry has the potential to improve the quality of the projects being delivered. However, more detail is needed before we can fully judge whether the mechanism will deliver its proposed outcomes. Ofgem's Draft Determinations is the first information we have seen on how this mechanism might function. No SQs or workshops focused on the SIF in advance of the Draft Determinations and therefore this does not form part our RIIO-T2 Business Plan. As such we haven't been able to forecast the likely effort and **resource required to support the competition**. This resource would be potentially in addition to resource already proposed to be reduced in our Closely Associated Indirect costs (see Question response to SHET Q10).

In order to be able to fully confirm our agreement with the SIF we would need to see detail on the following in **advance of the Final Determinations**:

1. Approach to aligning between public funding streams objectives
2. How the bid development timeline including submission will be managed?
3. What will the submission process look like?
4. How the SIF is to be financed including:
    a. the basis for determining the split between company contributions,
    b. how will funding flow through to non-network companies applying directly for funding, and
    c. the funding of the new assessment process?
5. How will the third party responsible for administering the fund be identified, appointed, funded and held accountable?
6. The efficient management of single topic innovation projects involving all sector parties

We are **concerned around the immature development** of the SIF and the lack of impact assessment on the impact of our RIIO-T2 Business Plan including resourcing, financing and planning for the SIF bids. We have outlined each of the six points above in further detail below.

1. Approach to aligning between public funding streams objectives

Potentially working across different funding stream could cause conflicts between the objectives of the individual funders. For example, areas such as the existing NIA Intellectual Property Rights (IPR) arrangements which aim to ensure that network customers benefit from IPR developed, can be misaligned with the objectives of some funders, who are specifically aiming to develop products and services, which can then be commercially exploited.

More detail on how Ofgem propose this to be managed would be essential to keep projects efficient and delivering maximum value. The timing of the various funding initiatives needs to be aligned and coordinated to allow appropriate projects to be developed.

2. **How the timeline round bid development and submission are to be managed?**

From our understanding of the Draft Determinations it appears that bid windows will not be the same time every year and the focus of each challenge will be defined as and when required. We support the agile approach of the SIF however we would welcome clarity on the likely timing of competitions given the potentially significant time that will be required for bid preparation. To ensure the SIF gets the best value for consumers, all bidders (including SHE Transmission) require adequate time to identify partners, engage with stakeholders, develop scope, budget and programme which will ultimately lead to higher quality, efficient and collaborative submissions.

From our experience of developing bids in RIIO-1 for the existing Network Innovation Competition (NIC), it is a lengthy and resource intensive process, taking up to nine months and costing in excess of £150k per bid to complete the bidding process. The focus of those bids has been challenges we face as an industry thus, we are familiar with the challenges and what the desired learning outputs are. With a potentially broader and less well-defined set of challenges it will likely take longer to develop a suitable bid to account for a new challenge and engage with potentially new partners in these challenges. These factors, combined with indeterminate bid windows, will make planning for submissions more difficult and costly across a price control. We are concerned this could have a negative impact on the quality of the bids and the cost of their development. Having a well-defined bid development process and timeline is essential for us to maintain our quality of submissions, develop relationships with appropriate stakeholders and partners and to identify the innovation benefits targeted by the framework.

3. **What will the submission process look like?**

Understanding the competition process, submission requirements and eligibility requirements will be welcomed. The existing NIC submission process, as noted above, is resource intensive, requiring development of a detailed bid document to meet the various eligibility criteria. This combined with clarity on the submission timetable will be required to allow SHE Transmission to develop comprehensive and robust submissions which will ultimately deliver benefits.

4. **How the SIF is to be financed including the split between company contributions, how will funding flow through to non-network companies applying directly for funding and the funding of the new assessment process?**

The current Network Innovation Competition (NIC) requires that licensees make a **compulsory 10% contribution** to the overall cost of a project. Understanding Ofgem's expectation of how this will change in the SIF and on what basis will be welcome. This is crucial to developing and financing the appropriate projects, making the necessary budget commitments and engaging with stakeholders. At the moment we are concerned that the SIF doesn't allow for this. We are not supportive of this level of uncertainty as it will **impair out ability to plan budgets** for innovation throughout the price control, this in turn will put at risk the number of projects we can engage with. This point is particularly pertinent due to the high risk and low returns nature of our proposed RIIO-T2 settlement.

A new element of the SIF over the NIC is that third parties will be able to apply directly for funding. Under current arrangements funding is recovered through network charges with the idea that associated innovation benefits will reduce overall network charges. It's unclear how that would work with a third party who does not directly affect the scale of network charges to recover these costs.

5. **How will the third party responsible for administering the fund be identified, appointed and held accountable?**

Having an independent third party to administer the fund has advantages as well as potential disadvantages. It will be key to understand the motivation and accountability of the party as well as any potential conflicts of interest. Transparency of: identification, appointment, work undertaken and decisions made through the appointment process and ongoing activities once appointed will help maintain trust in outcomes. Without this, issues could arise when it comes to bids being awarded or challenges identified.

Finally, the new third-party body who will administer the fund will require funding. As set out in more detail in the response to Q25, further detail will be needed on how this will be addressed to allow us to build up our plans for using this mechanism to support the transition to Net Zero. Transparency on the administrator's proposed funding would also be welcome

6. **How will projects be kept efficient when all innovation on a single topic must be contained within a single project involving all sector parties?**

When considering the portfolio of innovation through RIIO-1, there have been numerous projects targeted at various parts of the same topics, to provide an incremental and deliverable approach to complex network issues. For example, during RIIO-T1 there have been numerous projects looking at Active Network Management, each looking at different elements of the concept and how best to apply them. At the start of the first ANM project, although we had access to the learnings from previous projects, what was necessary to get most out of the concept wasn't known. Thus, building up a full project to deliver the technical, commercial and regulatory aspects would be a challenging and likely unsuccessful task. Additionally, there will be different schools of thought as to how best to deploy a technology or concept to a licensee and that could be different for each company. To try and put all of those conflicting views into one project will require a lot of development and thus make projects larger and have more risk attached, **even making project delivery a risk**. This could lead to inefficient, overly complicated projects.

Innovation activity does already have a high level of coordination and collaboration**. Coordinated by the ENA Innovation Managers Group, there is a strong history of collaborative projects amongst licensees**. A flexible approach is needed to allow innovation to progress incrementally, with the ability to respond to learning and stakeholder feedback. This can be achieved without the need for a single large-scale project which will slow progress and may discourage SMEs and innovators from participating and ultimately reducing progress.

***Core Question 25**: Do you have any comments on the additional issues that we seek to consider over the coming year ahead of introducing the Strategic Innovation Fund?*

We note that Ofgem aims to develop the following detail over the coming year:

1. the definition of 'innovation' for the purposes of the SIF
2. the possibility of using one public sector energy innovation interface through which companies would apply for energy innovation funding
3. the source of funds for the administration of the SIF
4. potential challenges for design-only early competitions
5. how we can build upon the existing joint gas and electricity innovation strategies network companies produce
6. how we can ensure network companies' knowledge dissemination activities build upon and link up with innovation activities funded by other bodies.

1. The definition of 'innovation' for the purposes of the SIF

When developing this definition, we think it worthwhile to consider that Net Zero can be supported in a number of ways, not just by facilitating whole system or by thinking about transport and the wider industry.

Delivering the network necessary to meet Net Zero will[15] require increased electricity demand[16] to be met through renewable energy. Note that the Committee on Climate Change have forecast a doubling of network demand (c.595TWh), which will need to be met by at least c.66% of renewable energy generation if Net Zero is to be delivered in the legislative timescales. This will require a large increase in renewable generation, which will need to be accommodated onto the electricity networks.

Innovation that can speed this up **via new construction methods, materials and processes will be invaluable to delivering on these targets**. We appreciate that innovation in these areas can be delivered through BaU, and where the risk is at an acceptable level, the benefits accrue to our own sector and/or are within the price control then we shall do so. However, we also recognise that certain innovations may not be developed if those conditions are not met and value may be lost. Thus, the definition should be flexible enough to allow the scope of these innovations to be included.

2. The possibility of using one public sector energy innovation interface through which companies would apply for energy innovation funding

We see the benefits in having one portal for a single application that covers all possible energy innovation funding. We would be keen to engage with the portal developer to help develop and test any ideas on this to ensure that it is fit for purpose from an applicant's point of view. Any new portal should include integration with or at least learn lessons from existing portals. There are existing industry portals such as the ENA Smarter Networks portal which allow applicants to

[15] As indicated in the ESO's 2020 Future Energy Scenarios across all scenarios
[16] E.g. as a result of increased uptake in EVs and decarbonisation of heat.

propose ideas to electricity licensees, these ideas are then reviewed via the ENA Innovation Managers group. Additionally, the ENA, Energy Innovation Centre (EIC) and SSEN have all run "calls" for applicants to propose ideas, which has resulted in the development of several successful projects such as TRANSTION, LEO and RaaS.

4. The source of funds for the administration of the SIF

We recognise that there will be costs with both identifying, appointing and then maintaining a third party to administer the SIF. There are obvious impacts if the source of this funding is to be included in the overall SIF pot or within some ratio for individual projects. If it were to be included on an individual project basis, then understanding of this would be essential to adequately forecast project budgets for submission. We would be happy for the current funding arrangements for programme administration to continue in their current form, i.e. that those costs are excluded from overall annual funding available.

We also feel that if there are multiple funding streams being applied through one governance process by the admin body, then those costs should be shared proportionally over each of the funds.

5. Potential challenges for design-only early competitions

We are unclear as to what this refers to; more detail is required.

6. How we can build upon the existing joint gas and electricity innovation strategies network companies produce

Through working between gas and electricity industries, a well-developed energy networks innovation strategy, that links across both sectors, that has been developed through engagement with stakeholders. As such, it provides a strong basis for the challenges foreseen and for the future for the network companies. It would be prudent for Ofgem to use this as a basis when feeding into the BEIS Innovation Strategy, that will seek to better coordinate energy innovation across the industries. However as this is network focused there may be potential conflicts, for example between what an energy supplier/developer/generator may want from innovation and what a demand user may want. A transparent approach to industry and stakeholder trade-offs will ensure funding is being used to deliver the greatest consumer benefit.

7. How we can ensure network companies' knowledge dissemination activities build upon and link up with innovation activities funded by other bodies

Requirements could be set on provision of funding such that key findings, associated with overlapping funding, can be disseminated jointly to shared stakeholders. Further requirements could include accounting for previous innovation in the area to ensure that previous work is not being duplicated. To allow this would need each funding stream involved to have a clear way of sharing what innovation had gone before, who was involved and what was learned. The ENA have a programme of shared dissemination events including conferences such as LCNI, forums and webinars, which are well attended and help coordination.

***Core Question 26**: Do you agree with our approach to benchmarking RIIO-2 NIA requests against RIIO-1 NIA funding?*

Yes, in part we do agree with benchmarking but do note the limitations of that approach and hence it should be a contributory factor only. The amount of money requested in RIIO-1 was set based upon the challenges faced at that time, notably to connect as much renewable energy as possible. The current challenges for RIIO-T2 include supporting the transition to Net Zero through whole system approaches to transport and heat, whilst continuing to connect as much renewables as quickly and efficiently possible. We also note there are regional differences which have emerged since RIIO-1 funding was allocated. In Scotland we have tighter targets on phasing out new internal combustion engine cars (2032) and when Net Zero (2045) has to be delivered. There are also devolved powers for energy efficiency and heat, which leads to differing approaches for those topics. This in turn can have varying network impacts that innovation can help address.

Accounting for these could mean that differing levels of funding compared with historical levels may be required by some.

***Core Question 27**: Do you agree with our proposal that all companies' NIA funding should be conditional on the introduction of an improved reporting framework?*

Yes, we agree that provision of funding is conditional on the introduction of suitable reporting. Development of such a framework is well progressed, subject to further information on the RIIO-2 settlement from Ofgem. We have been involved with the ENA work that has looked to expand upon the previous framework developed by the Energy Innovation Centre. The framework has been developed to be able to report on NIA factors and in time expand to BaU innovation funding. However, how the reporting framework will interface or include the SIF has not been considered due to lack of detail in advance of the Draft Determinations.

We also would like to note that we have only had written feedback on the development of the framework from Ofgem on the 17th of July. Considering the proposed deadline for a final proposal in time to allow for it to be accounted for in the Final Determinations to be published in December, that leaves little time to account for feedback.

Finally, we would like to reference that although this framework will be a way of forecasting and recording benefits, that the scale of these and their nature will vary from company to company as each license area will have different innovation focuses. Using these metrics to compare one company with another will not provide a true reflection of how each company performs innovation.

***Core Question 28**: What are your thoughts on our proposals to strengthen the RIIO-2 NIA framework?*

We fully agree with the following NIA reform areas:

1. Funding arrangements
2. Increasing third party involvement

We partially agree with the NIA areas of reform:

3. Scope of eligible projects
4. Considering the impact of innovation upon vulnerable consumers
5. Quality assurance of projects

1. Funding arrangements

We fully agree that the NIA funding allowance is provided for the full price control and not on an annual basis. The agility and flexibility of funding arrangements will help respond to the new challenges of net-zero. This will help avoid peaks and troughs at the beginning and end of the price control and give better flexibility with what projects to complete and at what speed to deliver maximum return on NIA investment by consumers.

2. Increasing third party involvement

We agree that clarification of IPR is an area that would benefit industry. As an industry we have learnt a lot about IPR over the RIIO-1 period. We suggest publication of an ENA led document would allow certain parties to engage more fully with the NIA process. That being said, under current innovation arrangements we do already engage extensively with third parties. Whether that be through innovation challenges and various SME engagements, supply chain or stakeholders helping form our overall innovation strategy and RIIO-2 plans.

3. Scope of eligible projects

We understand the defined scope but don't fully agree with it, as we feel that this will result in certain innovations not happening and would look for the eligibility to be widened. Projects that don't directly tie to supporting the transition to Net Zero or addressing consumer vulnerability may result in innovations that improve the design, development, construction or operation and maintenance of the networks not being taken forward. Specifically, if innovations on those areas deliver value outside the price control or are too risky, then it would not be suitable to fund these under BaU. That would leave certain projects that could add value across multiple licensees not delivering benefits to GB consumers and thus not being not being taken forward.

We also note that consumer vulnerability is a difficult topic to directly target transmission innovations to. Projects completed at transmission level tend to be large scale wider impact projects and have minimal engagement with domestic consumers, of which vulnerable consumers are a component of. Thus, as our stakeholder engagement for RIIO-T2 clearly realised, eligible projects in this area may involve looking at reducing overall consumer cost, which in turn could then feed into addressing customer vulnerability.

We also note that change in eligibility of funding where projects that are commercially available elsewhere are no longer eligible for demonstration in this country. We do not agree with this, as successful demonstration of an innovation elsewhere does not mean it will work for the GB system. GB operates within defined industry structures and involves different participants as well as having different legislation and commercial practices. To understand whether a non-GB innovation can work requires demonstrating against all of those parameters so that it can be rolled into BaU, which can be a large task. For example, SSENs RaaS NIC project builds on an earlier successful demonstration in Sweden of the use of renewable and energy storage to maintain network integrity. The RaaS project looks to test additional technical functionality and most importantly the business models and commercial arrangements which will ensure that the techniques initially demonstrated in Sweden can be applied within the GB network environment. Without NIA funding innovations may not be developed for GB application and potential value may be lost.

Following further engagement with Ofgem the TOs sent a joint letter on this topic. This is dated 25 August 2020: RIIO-2 NIA Project Eligibility Criteria to Graeme Barton.

4. Considering the impact of innovation upon vulnerable consumers

We partially agree. As noted above, the link between transmission companies and vulnerable consumers is challenging due to the lack of direct engagement, as that is traditionally completed by gas and electrical distribution companies. To ensure that we are able to assess an impact requires us to tie impacts to consumer cost and thus to vulnerable consumers. If Ofgem considers this form of vulnerable consumer assessment isn't appropriate, then it would be good to get a view from Ofgem on better alternatives.

5. Quality assurance of projects

We disagree. We already undertake rigorous governance at a company and ENA level to ensure that projects being completed are eligible and don't unnecessarily duplicate other projects. Thus, we are unclear of the benefits of this proposal and SSE fully reserves its position on this issue for further debate before the CMA, should it become necessary to do so.

If, despite the apparent lack of benefits, further measures were to be implemented, SSE suggests that these are undertaken on an ongoing business by network companies to ensure that maximum learning and project direction can be achieved for each project. If this process were to be undertaken by a third party then extra complexity and delays could be added to individual project timescales, thus taking longer to achieve the intended benefits.

We have three additional suggestions in relation to the Quality Assurance Framework:

We would require more detail on how this would work in advance of setting up any NIA projects. This would allow us to include aspects that would be tested by Quality Assurance (QA) upon completion of the project.

We would also need to understand the consequences of not meeting quality assurance requirements.

We also believe that the quality assurance test would need to recognise that projected outcomes from projects are based on assumptions made in advance of any trials. This can lead to outcomes needing to change midway through a project or even becoming undeliverable. In line with this we believe that QA should focus on quality of delivery and not necessarily on outcomes defined at the beginning of the project.

***Core Question 29**: Do you have any additional suggestions for quality assurance measures that could be introduced to ensure the robustness of RIIO-2 NIA projects?*

See our response to Core Q28 where we set out our opposition to Ofgem's quality assurance (QA) proposal and SSE fully reserves its position on this issue for further debate before the CMA, should it become necessary to do so.

We are unsure of the drivers behind this need for additional process for NIA projects. We are concerned that any potential additional QA process may create unintended barriers for smaller projects. We also consider that the innovation measurement framework being put in place may well address whatever the purported issues are.

There are strict governance processes already in place, both within SSEN and wider industry, ensuring that projects funded are eligible and work is not duplicated. At an SSEN level there is a board, the Innovation Strategy Board, led by senior management who provide signoff that funding is eligible as measured against the current NIA governance document criteria. At an industry level, the Electricity Innovation Managers Group, comprising representatives from all electricity licensee's, review all NIA proposals prior to registration. There is also a 10-day period put in place before all NIA projects are registered, to allow all stakeholders to review and provide comment on existing learning, any views on duplication as well as potential for collaboration.

Additionally, we feel that any new process would likely come with extra costs. Depending on the scale of the project, the increased cost may become a significant part of the overall project, potentially leading to inefficient project funding.

Finally, the innovation reporting framework being put in place will already go some way in helping address whatever the likely issues are driving this purported need. The framework will improve transparency of funding and improve visibility of innovation activity across all network licensees. With this in place and the existing processes described above, we assume that the drivers behind Ofgem's proposal would be sufficiently addressed in an efficient manner.

It should be noted that the vast majority of NIA projects generally involve an element of co-creation with stakeholders and partners. Often, this will involve them in investing time and money in order to participate in the development and delivery of NIA projects, which meet both the needs of the licensee but also the stakeholders. This ongoing commitment from third parties should give confidence in the quality of the NIA process, if the projects were not worthwhile then you would anticipate that this interest would reduce.

***Core Question 30**: Do you agree with our proposals to allow network companies and the ESO to carry over any unspent NIA funds from the final year of RIIO-1 into the first year of RIIO-2?*

Yes, we agree with the proposals as it doesn't negatively impact on consumer cost as it is simply a change in timeline rather than a change in allowance. This will avoid the potential cliff edge at the end of the price control and allow companies to better account for any delays from the final years of RIIO-T1 to any existing projects.

***Core Question 31**: Do you agree with our proposal that all work relating to data as part of innovation projects funded via the NIA and SIF will be expected to follow Data Best Practice?*

We do agree that innovation funded through NIA or SIF should follow Data Best Practice. Those recommendations are spelt out in the following document, https://es.catapult.org.uk/reports/energy-data-taskforce-report/ and are listed as:

- Digitalisation of the Energy System
- Maximising the Value of Data
- Visibility of Data
- Coordination of Asset Registration
- Visibility of Infrastructure and Assets

As we noted within supplementary question SHETL_SQ_CA_55 The recommendations of the Energy Data Task Force (EDTF) are specifically addressed in page 11 of the SHE Transmission Digital Strategy (T2BP-PAR-0006).

In order to put these recommendations into action, the Energy Networks Association (ENA), representing transmission and distribution network operators for gas and electricity in the UK and Ireland, has created a Data Working Group with further sub-groups formed to address specific aspects of the report. The Department for Business, Energy and Industrial Strategy (BEIS), Ofgem and Innovate UK have commissioned the Energy Systems Catapult to develop Data Best Practice Guidance to help organisations understand how they can manage and work with data in a way that delivers the vision outlined by the Energy Data Taskforce.

We are part of the ENA Data Working Group which has been formed to collaboratively address data issues, access new datasets and identify opportunities to derive value from existing datasets and to work with Ofgem, BEIS, Innovate UK and industry stakeholders to progress the recommendations of the Energy Data Task Force and deliver modern, digitalised Energy Networks for customers. As part of this collaborative approach we will continue to engage with stakeholders on use cases and data provision utilising a data triage process which presumes open data whilst maintaining cyber security and data privacy best practice.

We are very conscious that categorisation of data which should comply with data best practice guidance must be needs driven and driven by stakeholders'/users' needs. Planned investments and ongoing services must relate to the needs of direct users and ultimate benefits relate to wider stakeholders' needs. We take an open-minded view as to who the 'users' of energy systems data might be and we recognise that increasingly the users of energy system data are intertwined with many other systems, such as those of other utilities, finance, transportation and housing.

The recommendations have then been expanded upon through the Data Best Practise Guidance which can be found at the following address, https://es.catapult.org.uk/guides/energy-data-best-practice-guidance/.

That document states that the following principles should apply:

1. Identify the roles of stakeholders of the data
2. Use common terms within Data, Metadata and supporting information
3. Describe data accurately using industry standard metadata
4. Enable potential users to understand the data by providing supporting information
5. Make datasets discoverable for potential users
6. Learn and understand the needs of their current and prospective data users
7. Ensure data quality maintenance and improvement is prioritised by user needs
8. Ensure that data is interoperable with other data and digital services
9. Protect data and systems in accordance with Security, Privacy and Resilience best practice
10. Store, archive and provide access to data in ways that maximise sustaining value
11. Ensure that data relating to common assets is Presumed Open
12. Conduct Open Data Triage for Presumed Open data.

We note that within a recent keynote address “Welcome to Innovating to Net Zero”, Guy Newey of Energy System Catapult stated that “the creation and adoption of an open energy data and digitalisation governance framework in line with recommendations of the Energy Data Taskforce” is one of the “Priority policy measures to deliver Net Zero levels of Innovation“. We support this assertion and we are also supportive of the proposed Ofgem Licence Obligation requiring companies to work in accordance with the principles set out in Ofgem’s data best practice guidance to support the delivery of a digitalised energy system and maximise the value of data to consumers and we would support the application of this obligation to data associated with innovation funded through NIA or SIF.

As we noted within supplementary question SHETL_SQ_CA_55 The recommendations of the Energy Data Task Force (EDTF) are specifically addressed in page 11 of the SHE Transmission Digital Strategy (T2BP-PAR-0006).

***Core Question 32**: Do you agree with our proposed position on late competition?*

Overarching messages

Whilst we welcome Ofgem's proposal not to apply late models of competition to projects funded in baseline allowances or those where a decision has already been made to fund through an UM, we disagree with Ofgem's overall proposed position on late competition.

We disagree with Ofgem's proposal that all projects that meet the criteria for competition and are brought forward under an UM during RIIO-2 should be considered for delivery through a late competition model.

Electricity transmission services are a natural monopoly in infrastructure design, build and operation. It is our experience, supported by comparative analysis of cost bases, that long run average costs fall as the infrastructure grows. Our experience also demonstrates the importance of sustained and committed asset stewardship in long term planning and stakeholder relationships is in the provision of a public good. We therefore have serious reservations about mechanisms that would lead to fragmentation of existing transmission network. We are also mindful of the potential impact that a fragmentation of responsibilities will have on the industry's ability to manage and maintain an economic, reliable and safe network. The introduction of several interfaces between the TOs, ESO, CATO and other commercial market players must be the subject of a robust impact and risk assessment with clear delineation of roles, responsibilities and liabilities for the future operation of the GB network. Additionally, economic theory and experience from other utility sectors demonstrates that there are potentially significant consumer disbenefits that need to be considered and mitigated in the design of such mechanisms.

Late models

We disagree with Ofgem's classification of the CPM, SPV and CATO models as "existing" models. All three models remain at a very early conceptual stage of development and Ofgem has recognised that there are a number of outstanding issues yet to be addressed by Ofgem before they could conceivably be progressed. None of these models has, in fact, been applied to any project and, indeed, at least the CATO model would require primary legislation before it could be taken into consideration. Moreover, there are serious concerns as to whether any of these models could be implemented in compliance with Ofgem's statutory duties and the current licensing framework.

With regards to the CPM and SPV models, beyond the brief overviews provided in the supporting appendices of the SSMD, Ofgem's Draft Determinations document does not contain any meaningful detail on the design of the models. Ofgem's position at the time of the SSMD was that it would *"[10.93]..continue to develop the relevant areas of policy in due course".* To our knowledge, no further development of these policy areas has taken place and there is no indication that our previous concerns have been taken into account. As no further details on the three late models have been presented in the Draft Determinations, we cannot comment on their suitability. Given the previous issues we have raised in relation to the models in separate consultations during RIIO-1, on which a substantive response from Ofgem has not yet been forthcoming, it is incumbent on Ofgem to set out clearly whether, and in what manner, Ofgem has further developed its policy on, and the detail of, alternative models and how Ofgem has addressed the significant concerns previously raised by SHE Transmission (and other industry participants).[17] Unless and until Ofgem does so, we are not in a position to set out our response to Ofgem's current (yet to be articulated) policy on any of these models. It is nevertheless clear that it would be unreasonable, and not in accordance with its statutory duties, for Ofgem to make determinations on the suitability of these models for projects brought forward under RIIO-2 before the models have been fully developed. Similarly, introducing licence conditions to enact these underdeveloped models is inappropriate.

We therefore welcome Ofgem's verbal update at its July Licence Drafting Working Group (LWDG), that licence conditions for the SPV and CATO models would not be brought forward for the start of T2 and instead would only be considered separately, if and when those models had been developed further following a full consultation at that time, as appropriate.

We remain concerned, however, that Ofgem is continuing with the implementation of its proposed CPM licence condition. The CPM "model" is no better developed than the other potential models Ofgem has referred to. There has been no specific CPM consultation setting out Ofgem's view of how CPM will be applied and operated during RIIO-2. Our last substantive engagement with Ofgem on the development of the CPM was at the beginning of 2019 (notwithstanding our consultation responses to the Scottish Island Needs Cases), following a series of workshops in 2018 where we, along with the other TOs, provided feedback on the proposed model and early-stage licence drafting presented at that time. Following the workshops, there remained a number of outstanding and significant issues which we outlined in letters to Ofgem on 22 January, 28 February and 22 March 2019. At that time Ofgem committed to responding to the outstanding issues raised by each of the TOs before then commencing a specific consultation on the CPM and the associated licence drafting. However, notwithstanding that clear commitment, no response from Ofgem was ever received and later in Summer 2019 Ofgem advised that it was postponing the consultation on CPM. We have received no further update since and the serious issues raised in our correspondence have not been addressed. These issues have likewise not been considered in any part of the RIIO-T2 process or in the Draft Determination.

In particular, when Ofgem's initial thinking on CPM was first raised in the context of RIIO-T1, we raised several substantive concerns in relation to the operation of the financial model underpinning the overall CPM policy. We are not aware that Ofgem has undertaken any work on the financial model since it was initially considered in 2018 and understand that Ofgem decided that the required further work should be paused at the beginning of 2019. We strongly refute Ofgem's suggestion that application and operation of the CPM does not form part of overall policy. Ofgem has also continued to state that TOs do not necessarily need to adopt the proposed Amberside Model when considering project financing and the possibility remains that a TO could bring forward a separate project financing model. We and other TOs stressed the importance of introducing a standardised, robust, auditable model which is fit for purpose and can be replicated across all competitively assessed projects. Across the three TOs, the value of schemes under which Ofgem may apply the CPM has the potential to exceed multiple billions of GBP. Therefore, the governance of any associated financial model must be enshrined within the regulatory framework consistent with the Price Control Financial Handbook and Price Control Financial Model (PCFM). The approach

[17] Including SSEN responses (and accompanying expert reports) to Ofgem's consultations on the SPV model framework in November 2018, on proposed WACC for the CPM model in October 2018, on Ofgem's impact assessment for the CPM and SPV models of November 2018, in response to Ofgem's SSM consultation in March 2019 and in response to Ofgem's consultations regarding the delivery models for the Hinkley-Seabank, Orkney, Western Isles and Shetlands transmission projects in 2018 and 2019.

to governance would also extend to the management of change, consultations and appropriate external audit of the model. Failure to do so would not be in accordance with Ofgem's statutory duties.

Ofgem's proposals to include an ill-defined and undeveloped CPM model on which significant concerns have yet to be addressed or consulted upon during RIIO-T2 creates significant uncertainty in terms of financeability where the potential application of a cost of capital within the CPM model may be different to that of the wider price control. We remain specifically concerned about a number of aspects of Ofgem's proposals regarding how he cost of capital for CPM is to be set. We consider it of the utmost importance that Ofgem clearly outlines and consults on the CPM financial modelling and associated governance structure. Unless SHE Transmission (and other stakeholders) are afforded an appropriate opportunity to consider and consult on the detail of the proposed approach, the current CPM proposals could not be included as part of Ofgem's Final Determinations.

Impact Assessment for Late Competition

We challenged the robustness of Ofgem's supporting IA for late competition in our response to the SSMD and provided detailed evidence in this respect which illustrated, among other things, that the perceived consumer benefit from alternative models (as then proposed) was illusory. We note that this evidence has not been acknowledged or addressed within the Draft Determinations. In those circumstances, we disagree that the benefit case to consumers has been demonstrated by Ofgem in making its determination to apply any late model to transmission projects. At its core, the 'potential savings' quantified in the IA rest on a possibility that fixing the cost of debt for the lifetime of a project may turn out to be cheaper for customers than applying the relevant RIIO cost of debt indices. This possibility is entirely contingent on capital market conditions and is not a robust basis for introducing a new regulatory model and exposing customers to the risk of significantly higher bills.

As no comprehensive impact assessment or cost benefit analysis of competition for onshore transmission has been undertaken, there is a clear lack of any compelling justification as to why the late competition models should be adopted.

Ofgem has also itself acknowledged that – due to the 25 year operational period for the late competition models – there may be a risk of intergenerational inequity. Ofgem's stated basis for nevertheless pursuing proposals which admittedly give rise to this serious risk is "the overall level of savings available".[18] However, we have previously provided evidence that the "level of savings" Ofgem was assuming is very unlikely to be available in practice. No updated cost benefit analysis has been undertaken since. There is therefore no current evidential basis for any claim that the "overall level of savings" outweighs the acknowledged concern around intergenerational inequity which SSE has brought to Ofgem's attention previously.[19] Indeed, the risk of intergenerational inequity is a compelling reason not to proceed with any late competition models during RIIO-T2.

[18] Ofgem, Impact Assessment on applying late competition to future new, separable and high value projects in electricity and gas networks during the RIIO-2 period, May 2019, page 27.
[19] See, for example, Scottish Hydro Electric Transmission's response to Final Needs Case Assessment: Shetland Transmission Project, May 2019, Schedule 2, para 2.12 and 2.13.

We welcome Ofgem's recognition that before applying any late models to specific projects, it will assess the consumer impact and network company financeability; however, Ofgem must also consider customer impact (e.g. contracted generation) and net zero targets within this assessment. Further detail is required on the scope of the project specific IA to allow us to respond fully on these proposals.

Additional comments

We are concerned by Ofgem's proposal that TOs "do not carry out any development work on eligible UM projects that is detrimental to the application of late competition". This proposal lacks any detail to allow us to assess the effect in practice and would inevitably lead to delays to project delivery. The preconstruction process is critical for the successful delivery of the increasing renewables driven investment in the network by ensuring we are ready to connect and transport new generation at the right time and in the right location. It is through rigorous and thorough preconstruction that innovative and whole system solutions are identified, risks for the construction phase are mitigated and all stakeholders can participate in co-creation of the optimal system development pathway. We refer Ofgem to our response to ET Q11 for further detail on pre-construction funding.

It is unreasonable for Ofgem to ask TOs to delay the development of projects or parts of projects that could be considered separable and eligible for competition, because of the uncertain possibility that Ofgem could at a later date, and in unclear circumstances, decide to apply a late competition model. This could result in potentially significant additional cost, borne by the TOs' customers and the GB consumer, could affect a TO's ability to meet its obligations to maintain the security of the electricity network or put it in breach of its obligations to meet contracted connection dates.

In addition, as noted by SHE Transmission in previous consultation responses,[20] Ofgem's proposal would also seriously undermine certainty in the regulatory framework, which is vital for licensees, generators, customers and all relevant stakeholders including investors, particularly in the current uncertain investment climate. Certainty in the regulatory framework is particularly significant when it underpins the financing, construction and operation of new transmission assets.

For clarity, our Skye project was not assessed against Ofgem's competition criteria as it did not sit within the Certain View in our BP, therefore we were not seeking baseline allowances for this project (beyond PCF). Ofgem's suggestion that we did not assess the project against the competition criteria because it was not assessed by the ESO as part of the NOA is incorrect. We will be seeking funding for Skye through the appropriate UM in RIIO-2, at which point the project would be assessed against Ofgem's eligibility criteria.

[20] See, for example, Scottish Hydro Electric Transmission's response to Final Needs Case Assessment: Shetland Transmission Project, May 2019, Schedule 2, para 2.14.

***Core Question 33**: Do you agree with our proposed approach on early competition?*

We welcome Ofgem's recognition that key aspects of the early competition policy are still to be developed and therefore that it is not yet appropriate to finalise proposals for how early competition will be incorporated into RIIO-2.

We have recently submitted our response to the ESO's consultation on its ECP where we have outlined our detailed views on the proposals being made. We therefore welcome Ofgem's approach to consult fully on its early competition proposals only following the outcome of the ESO's work.

We welcome Ofgem's proposal that projects that receive baseline funding will not be considered for delivery through early competition models.

Notwithstanding the above, we are concerned with the pace of policy change in this area. We are yet to be convinced that Ofgem has demonstrated that any proposed approach to introduce competition in network planning will protect the needs of consumers today and in the future, more so than the existing framework. In particular, no comprehensive impact assessment or cost benefit analysis of competition for onshore transmission has been undertaken. We also understand that this activity is not within the scope of the ESO's work to develop its ECP. This makes it challenging to both develop such a regime (learning lessons from other utility sectors) and, where competition is assessed to be potentially beneficial, ensure that the regime optimises the benefits.

In addition, we have serious reservations about mechanisms that would lead to fragmentation of existing transmission network. We are also mindful of the potential impact that a fragmentation of responsibilities will have on the industry's ability to manage and maintain an economic, reliable and safe network. The introduction of several interfaces between the TOs, ESO, CATO and non-network solutions must be the subject of a robust impact and risk assessment with clear delineation of roles, responsibilities and liabilities for the future operation of the GB network. Our experience demonstrates the importance of sustained and committed asset stewardship in long term planning and stakeholder relationships is in the provision of a public good. We are primarily concerned with ensuring any new model strikes the right balance between bringing demonstrable savings to consumers; ensuring Ofgem can protect the interests of existing and future customers; and enabling TOs and the ESO to continue role of ensuring the safety, efficiency and security of the network.

If the ESO and Ofgem do not have the vires to conduct a comprehensive assessment of the potential costs and benefits of potential models, then any conclusions it reaches should be clear that these are subject to such assessment.

Our position remains that Ofgem (and the ESO) should not pursue competition at all costs i.e. competition for competition's sake. The introduction of competition constitutes a major market intervention carrying risk of unintended and adverse consequences; the development of competition policy must be conducted in a safe and responsible manner.

As clearly articulated by Ofgem, "GB has one of the world's most reliable and safest energy systems, with power cuts half the EU average and customer satisfaction with networks at a record high." This is testament to the success and strength of the existing framework, under which consumers benefit from direct engagement with the TOs and ESO, and the regulator acting as a proxy for competition to keep costs down and service levels high.

***Core Question 34**: Do you agree with our view that SHET, SPT, SGN and WWU passed all of the Minimum Requirements, and as such are considered to have passed Stage 1 of the BPI?*

We agree with Ofgem’s view that SHE Transmission has passed all the Minimum Requirements to have passed Stage 1 of the BPI.

We unable to determine whether each of SPT, SGN and WWU passed stage 1. Only Ofgem and those network companies and their associated User Groups and Customer Engagement Groups are in a position to provide a fully informed response.

***Core Question 35**: Do you agree with our rationale for why NGET and NGGT should be considered to have failed Stage 1 of the BPI?*

N/A

Only Ofgem and those network companies and their User Groups are in a position to provide a fully informed response.

***Core Question 36**: Do you agree with our rationale for why Cadent and NGN are considered to have passed Stage 1 of the BPI?*

N/A

Only Ofgem and those network companies and their associated Customer Engagement Groups are in a position to provide a fully informed response.

***Core Question 37**: Do you agree with our overall approach regarding treatment of CVP proposals?*

No, we do not agree with the overall approach regarding the treatment of CVPs and more widely we believe Ofgem has failed in its policy intent of providing an incentive to reward high quality ambitious Business Plans through the Business Plan Incentive (BPI). Please refer to SHET Q4 and SHET Q5 which contain our detailed response to Ofgem's comments on our proposed CVPs.

In attempting to reward high quality plans, Ofgem developed the CVP concept in June 2019 when the first draft of Business Plans were complete and this became the only means of rewarding high quality plans. This remains largely conceptual without timely detailed guidance on application.

Our view is that: 1. this new CVP approach as implemented did not align policy intent of the BPI and this failure lies with Ofgem process and not with lack of ambition; and 2. there were flaws in the CVP assessment approach ultimately adopted by Ofgem.

Failure of policy intent of rewarding quality

Ofgem's lack of guidance on CVPs meant that network companies were putting forward proposals against an evidential bar which was unclear. Despite unclear, evolving and late guidance on the CVP from Ofgem (see points on process below), what remained was a consistent Ofgem policy intent. From the Framework Decision in July 2018 to the Business Plan Guidance in June 2019 when CVPs were outlined and the final Business Plan Guidance in October 2019 the intent was clear: there would be an incentive on companies to submit innovative high-quality Business Plans developed through engagement with stakeholders. As such, demonstrating ambition and added value to meet our stakeholders' expectations was always at the forefront of our Business Plan proposals.

Despite this, the summary rejection of our CVP proposals by Ofgem outlined in core SHET Q4 has been repeated across the transmission and gas distribution sector, and in doing so Ofgem has **failed to follow through in its policy of rewarding high quality plans.**

The monetisation of CVP was, in practice, the only way in which licensees could earn an upfront reward through the BPI. Despite Ofgem's policy intent to provide companies with upfront rewards for delivering high-quality ambitious Business Plans, very few rewards were provided in the Draft Determinations. In fact, out of 117 CVP proposals put forward by network companies (with a total value of over £5.5bn), only two were granted a reward (calculated by Ofgem as £1.6m each). Our biodiversity CVP was accepted in principle by Ofgem, but Ofgem has disputed the valuation methodology without proposing an alternative.

For this to emerge systematically across the network sectors is not down to a lack of ambition on the part of the licensees particularly given the User Group and Customer Engagement Group support for CVPs. Rather, the poor guidance upfront, changing methodology, late guidance on CVP and poor assessment at Draft Determinations has driven the outcome – Ofgem has not been clear on what it has wanted or how it would measure quality and ambition, and this has left making its assessment challenging.

Nonetheless, the policy intention of incentivising ambitious and quality Business Plan has remained and stakeholder support demonstrates that SHE Transmission has certainly delivered on it. It is imperative that Ofgem recognises this and does not allow its own process shortcomings to "design-in" the wrong outcome and one that is inconsistent with its policy intent. On the other hand, Ofgem has been far less cautious about applying the maximum possible penalties for what it deems poor quality Business Plans (i.e. those plans that are deemed not to have met minimum standards) or those where Ofgem propose are inefficient (e.g. levying a £32m penalty on SHE Transmission – see section 3.2 in our Main Response). The approach is entirely inconsistent.

Looking forward to future price reviews including RIIO-3 and ED-2, there is little incentive for network companies to put forward ambitious plans. The clear signal from to network companies is to aim for minimum standards and do not respond to stakeholder ambitions as there is little benefit (and potential penalties) in seeking to do more. The only potential (limited) rewards are through the delivery incentives (the TIM and ODIs) once baseline allowances have been set. Again, this is inconsistent with Ofgem's policy intention for ambition and innovation.

Ofgem must recognise our ambition – through the clear strategic approach we have taken – and reward accordingly. Failure to do so would be a failure to reward quality and ambition within the plan.

Process: the evolving and limited CVP guidance

The below demonstrates that the process for Ofgem's CVP/quality assessment of plans falls short of good practice. Companies needed to submit their Business Plans based on this evolving picture. Nonetheless, as noted above, there was a consistent intent to reward quality and Ofgem's the ambitions of licensees should not go unrecognised due to Ofgem's shortcomings on process.

July 2018: RIIO Framework Decision: Ofgem proposed to remove early settlement as a procedural incentive but acknowledged that other incentives would be needed to encourage high-quality Business Plans, including upfront rewards (or penalties). Transmission companies were generally in favour of removing early settlement as an incentive *so long as an alternative was adopted* for rewarding high-quality Business Plans.

December 2018: Sector-Specific Methodology Consultation: Ofgem restated its policy intent and set out more detail on its plans for a new BPI.

"In Chapter 9, we describe our proposal for a new Business Plan incentive. This will involve an assessment of the cost *and quality* of Business Plans. Our proposal is that *high quality plans would have the ability to earn a financial reward* and companies submitting poorer quality plans may face a financial penalty."[21] [emphasis added]

The approach envisaged a four-step methodology. A matrix approach was to be adopted to ascertain the potential for rewards by combining scores on costs (stage 2) and qualitative issues (stage 3). However, for stage 3, while mentioning qualitative aspects that might be considered, this did not set out comprehensively the areas of assessment or assessment criteria. This detail was left

[21] RIIO-2 Sector Specific Methodology Consultation, paragraph 3.10. https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-consultation

to the Business Plan Guidance. The Business Plan Guidance of December 2018 similarly provided limited guidance on what might constitute a good or poor quality plan.[22]

May 2019: Sector Specific Methodology Decision: late changes were made to the BPI including a reordering of the assessment process and the introduction of the consumer value proposition (CVP) concept.[23]

June 2019: Business Plan Guidance: first publication with any detail of the CVP including monetisation was published but this was still limited.[24] There were further late changes to the CVP guidance in September 2019 around beyond-minimum criteria and monetisation.[25]

Process: the comparative approach – Ofgem v Ofwat

Ofgem's process can be contrasted with that adopted by Ofwat in the England and Wales water sector. In PR19, Ofwat proposed at an early stage that there should be upfront positive rewards for delivering high-quality ambitious Business Plans.

A clear exposition of its approach was provided upfront in its 2017 methodology.[26] There was to be an initial assessment of plans (IAP) stage in 2019. In the methodology, Ofwat set out the IAP objectives, test areas, characteristics, categories and incentives. The approach remained little changed over time, and detailed explanations were provided at the IAP stage in 2019 for the assessments.[27]

Ofwat's approach led to three companies being fast-tracked and receiving financial rewards for putting forward what it regarded as high-quality Business Plans. There is a debate as to whether these fast-tracked rewards were sufficient.[28] However, what can be observed is that Ofwat's intended guidance and process was clearer than that of Ofgem.

In our response to Ofgem's Business Plan Guidance consultation in December 2018, we strongly recommended Ofgem adopting a similar approach regarding test areas, characteristics and categories. The rationale for choosing a different approach was not communicated.

The key issue with Ofgem's guidance is that, although the need for rewards was acknowledged at the outset, the guidance was insufficiently clear and changed over time.

The assessment framework changed ahead of Business Plan submission, including through the introduction of the CVP (and the subsequent drip-feeding of information regarding its operation).

De facto, at Draft Determinations, the CVP became the only means for companies to earn a reward. However, ahead of Draft Determinations, the way in which CVP proposals would be assessed was unclear. This is likely to have played a role in the low number of CVPs being accepted by Ofgem at

[22] Reference unavailable on Ofgem website.
[23] https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-decision
[24] https://www.ofgem.gov.uk/publications-and-updates/riio-2-business-plans-guidance-document
[25] https://www.ofgem.gov.uk/publications-and-updates/riio-2-business-plans-guidance-document
[26] Ofwat 2017, *Delivering Water 2020: Our Final Methodology for the 2019 Price Review*, December
[27] Ofwat 2019, *PR19 Initial Assessment of Plans: Summary of Test Area Assessment*, January, plus company-specific annexes.
[28] Part of this is because, at PR19, fast-tracked companies still faced further challenges on costs and other areas at Final Determination. This was in contrast to PR14.

Draft Determinations, and the low associated rewards, which would appear out of line with Ofgem's policy intention.

In contrast, Ofwat's approach led to three companies receiving financial rewards for putting forward what it regarded as high-quality Business Plans (albeit that the overall benefits of fast-tracking were lower than at PR14). A clearer exposition of its approach was provided upfront. This included the IAP objectives, test areas, characteristics, categories and incentives. The approach remained little changed over time, and detailed explanations were provided at the IAP stage for the assessments.

Key observations between Ofgem and Ofwat's process is provided below.

Ofgem	Ofwat
Ofgem's process changed a number of times since the July RIIO-2 decision. In July 2018, Ofgem put forward a policy intent that high-quality plans should receive upfront rewards. This was acknowledged by Ofgem as a necessary consequence of ending fast-tracking Ofgem did not set out firm proposals of how it would undertake its assessment of Business Plans in its July decision; this was left until later (a feature repeated in Ofgem's subsequent decision-making) The approach set out in the December 2018 sector-specific methodology envisaged a four-step methodology. A matrix approach was to be adopted to ascertain the potential for rewards by combining scores on costs (stage 2) and qualitative issues (stage 3). However, for stage 3, while mentioning qualitative aspects that might be considered, this did not set out comprehensively the areas of assessment or assessment criteria. More detail was left to the Business Planning Guidance. The Business Planning Guidance of December 2018 similarly provided limited guidance on what might constitute a good- or poor-quality plan Following stakeholder feedback, late changes were made to the BPI in the May 2019 decision, including a reordering of the assessment process and the introduction of the CVP concept. Limited guidance was provided on the CVP in the revised June 2019 Business Plan Guidance	Ofwat's approach was from the outset clearer than that of Ofgem. It also was more consistent over time—in part as there were fewer iterations built into the process. Observations are as follows: Ofwat was clear upfront in its December 2017 methodology that fast-tracking would be retained, and that exceptional and fast-tracked companies would receive upfront financial rewards in addition to procedural and reputational benefits The IAP process was set out upfront in the methodology, including the objectives, test areas, characteristics, categories and incentives. This was to give a clear indication to companies of how to prepare their Business Plans, and to enable Ofwat to carry out the IAP process effectively and efficiently. Nine IAP test areas were set out and test questions were also proposed. The IAP assessment would take into account all nine areas. Ofwat committed to providing exceptional companies an additional 20 basis points (bp) to 35bp to the RoRE. Fast track companies would receive an amount equivalent to a 10bp addition to the RoRE. Ofwat provided its IAP assessment in January 2019, broadly in line with its stated methodology of 2017. Companies were provided with annexes specific to them, setting out in detail the IAP assessment in each area. The IAP phase provided the ability for other companies to adjust their plans ahead of the Draft Determinations.

There were further late changes to the CVP guidance in September 2019 around beyond-minimum and monetisation. Companies needed to submit their Business Plans based on this evolving picture. There was only brief explanation provided to companies at Draft Determinations as to why their CVPs had been rejected, and only two (plus one) were accepted in practice of the 117 put forward. In effect, as most companies were penalised in stage 3 (low-confidence costs) and no companies received a reward in stage 4 (high-confidence costs), stage 3 (CVP) was the only way in which companies de facto could receive rewards.	Three companies were fast-tracked at the IAP stage, receiving financial and other (procedural, reputational) rewards.

Issues with the CVP approach

We set out our approach to CVPs as part of the supplementary question process in a paper to Ofgem attached in appendix "T2BP-DD-SHE-001 SSEN Transmission - Consumer Value Proposition (CVP)" in response to a number of supplementary questions on our own CVPs and our concerns on how Ofgem was approaching CVPs. We believe our approach was a reasonable and our key concerns raised in that paper regarding Ofgem's approach still stand following the publication of Draft Determinations. These are:

- Ofgem dismissed a number of CVPs as being BAU but beyond setting minimum requirements, Ofgem failed to define what it meant by BAU in the Business Plan Guidance. As detailed in the paper, SHE Transmission developed its own definition of BAU, which went beyond simply meeting the minimum requirements and yet some of our CVPs were still rejected on this "BAU basis".

- Throughout its assessment of CVPs, Ofgem has not demonstrated consistency in approach but instead relied wholly on regulatory judgement to dismiss evidence-based proposals.

- Ofgem consistently stated it would take a qualitative approach to assessing the quality of Business Plans but has focussed solely on a quantitative approach whereby only elements that can be monetised in terms of added consumer value are considered for a reward to reflect quality. For example, Ofgem failed to recognise that SHE Transmission is the first network company globally to set the most ambitious 1.5 degree science base targets to reduce our carbon emissions as we put this forward as a qualitative CVP (as area specifically recognised by our User Group as going above and beyond – page 45 of the User Group report).

- Exacerbating the above, Ofgem failed to provide detailed guidance on monetisation methodologies but rejected many reasonable approaches taken by all companies to determine a consumer value, where monetisation was possible. For example, our approach to monetising Biodiversity impacts was rejected. In response to Ofgem's decisions we proposed several alternatives to valuing BNG including taking our own initiative to engage with NGET TO. Despite efforts to come to an agreed approach, there's been limited direction from Ofgem and we are advised that this might now take place after 4 September. Nonetheless, we will continue with engagement to reach a position. Therefore, for the purposes of this response we have been unable to provide a revised value for BNG.

- Ofgem has failed to recognise that the monetisation value does not have to equal the BPI quality reward. Rather, it is a basis on which to form that reward. For example, while our Commercial and Connections service delivers additional value to consumers of £60m and the amenity value of our biodiversity activities is valued at £159m, we are not seeking a reward of £219m but asking Ofgem to consider this value as part of its wider qualitative assessment in rewarding our Plan for quality and ambition. See our response to SHET Q4.

- Ofgem has failed to consider the views of stakeholders on quality and ambition of our Business Plan. For example, our User Group on CVP who have been particularly supportive of our Commercial and Connections service and sustainability related ambitions and recognised these as above minimum requirements (see pages 13 and 43-45 of the User Group report).

- Ofgem's focus throughout the supplementary question process has been largely on how to clawback any reward made leading to the narrowing of any potential CVP reward to those areas that can set baselines and mechanically clawback rewards based on targets not met. This is the purpose of output delivery incentives (ODIs) not CVPs. While we fully committed in our Business Plan to return an equivalent and proportionate CVP value to consumers for activities not delivered, being held to account through our Enhanced Reporting Framework (ERF), this requires a qualitative assessment and not a mechanistic clawback method that Ofgem favoured. Our suggested approach was clearly set out in the appendix "SHE Transmission CVP Approach. We also clearly set out where baseline targets would be inappropriate given the innovative nature of initiatives. For example, our Commercial and Connections Policy where instead we proposed KPIs and reporting to our new stakeholder groups as outlined in response to SQ 25 and SQ 40. However, this was not recognised by Ofgem in its Draft Determinations whereby it set out concerns of baselines.

In relation to all the points above there was lack of detail and impact assessment in the Draft Determinations decision in relation to CVP.

***Core Question 38**: Do you agree with our proposed clawback mechanism to treat received CVP rewards?*

We agree that any clawback should be done by revising the revenue awarded through the PCFM at the RIIO-T2 Close Out and not before. Any claw back for non-delivery must be capped at the value that the specific CVP item as rewarded as. We also support scaling the CVP clawback to a proportion of the total BPI reward from Stages 2 and Stages 4.

We agree that there should be a clawback mechanism and clearly stated this in our Business Plan. Our commitment to deliver our CVP proposal formed part of our Output Commitment; if we don't undertake the activities that deliver any rewarded CVP value, we committed to return an equivalent and proportionate CVP value to consumers. This was specifically recognised by our User Group (page 43 of our User Group report). But as noted in response to Q36 we have concerns that Ofgem's narrow focus on designing mechanistic clawback has contributed to Ofgem's failure to deliver on its policy intent to reward quality and ambitious plans through the BPI.

As outlined in stage 5 of appendix "T2BP-DD-SHE-001 SSEN Transmission - Consumer Value Proposition (CVP)" which we submitted as part of the supplementary question process, we believe a clawback mechanism will provide an incentive for companies to deliver consumer value via CVPs throughout the price control. This will also ensure that companies remain accountable and transparent to stakeholders (including Ofgem) and consumers.

As the process for assessing the CVPs should be qualitative, we consider it is appropriate that the process for assessing CVP output delivery must also be qualitative. Therefore, we support Ofgem's position of the use of performance metrics to help determine if CVPs have been delivered rather than basing it on actual consumer benefits. This is why we have set out KPIs for our CVPs.

We also believe that in some cases we may need to adapt our KPIs meet the challenges of net-zero or changing needs of our stakeholders. Therefore, we proposed that we be held accountable through our new 'User Group', our 'Network for Net Zero Stakeholder Advisory Group' (see our response to core Qs 1-5 for further detail) and through enhanced annual reporting, which could include KPIs. Examples of suggested KPIs are detailed in our response to SHET Q4 relating to our Commercial and Connections CVP 2.

We welcome further engagement ahead of Final determinations with Ofgem on both the proportion of clawback mechanism that might be appropriate for each CVP as well as the performance metrics and reporting associated with them.

***Core Question 39**: Do you have any views on the interlinkages explained throughout this chapter?*

SHE Transmission does not dispute the general principle that certain elements of the RIIO-2 price control may relate to other aspects of the determination.

However, as set out in **Section A** below, SHE Transmission does not consider that it is a useful or appropriate exercise to attempt to enumerate or categorise the relationships in the abstract, particularly in advance of the Final Determination. We understand the term "interlinkages" in Q39 is referring to a legal concept developed in the decisional practice of the Competition and Markets Authority (***CMA***). In that context, the question of whether any interlinkage arises can only properly be assessed on a case-by-case basis in light of the specific flaws identified in grounds of appeal raised in respect of Ofgem's final price control decision. Moreover, it is clear that in certain cases an imbalance in the price control caused by a specific flaw in Ofgem's decision can properly be corrected by a change to only one of a number of related aspects thereof. Whether any relevant interlinkages exist (in the sense used by the CMA in its decisional practice) and, if so, the consequences for any remedy that the CMA orders to correct Ofgem's decision is a matter for the CMA, and not Ofgem, to determine. Since the issue of interlinkages only arises at the appeal stage, SHE Transmission fully reserves its position on this issue for further debate before the CMA, should it become necessary to do so.

Moreover, as set out in **Section B** below, while SHE Transmission would anticipate articulating in any appeal notice any relationships in the price control that relate directly to its grounds of appeal, it strongly rejects Ofgem's suggestion that it is for appellants to identify and raise all possible interlinkages either in its notice of appeal or (even more so) in advance of Ofgem's Final Determination. As is clear from the decisional practice of the CMA, it is for Ofgem, in the first instance, to explain any relevant interlinkages, and fully set out its position on how they should be addressed, in its response to any notice of appeal. An appellant is then given the opportunity to respond to Ofgem's position. SHE Transmission fully reserves its position in the event of any appeal to the CMA in respect of any position on interlinkages that Ofgem may put forward at that stage.[29]

Even if it were open to Ofgem to raise a defence based on interlinkages pre-emptively (which is not the case), Ofgem's "*high-level view of how the different elements of the RIIO-2 price control framework interact with each other*"[30] which is "*not an exhaustive list*"[31] is clearly insufficient to discharge Ofgem's burden in this regard. Given that Ofgem does not currently know which elements of its decision may or may not be appealed, engaging in a vague and incomplete exercise of setting out possible and hypothetical interlinked aspects of the decision at this stage in the process does not allow for any meaningful or comprehensive discussion of interlinkages. As outlined in SHE Transmission's response to the Post Appeal Proposal (Q.41), the CMA is the body which will consider potential interlinkages in any future appeal determination and Ofgem cannot bind the CMA, nor avoid its burden of raising potential interlinkages at the appeal stage in the current consultation on the Draft Determination.

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[29] CMA BGT ED1 Determination, para 3.52; CMA NPg ED1 Determination, para 3.51.
[30] DD, Core Document, para 11.2.
[31] DD, Core Document, para 11.10.

A. The existence of interlinkages in the price control

While SHE Transmission accepts the principle that certain elements of the RIIO-2 price control may relate to other aspects of the determination, it would caution against attempting to enumerate the potential interlinkages or categorising them in the abstract as "mechanistic" or "in the round" interlinkages as Ofgem has done in Chapter 11 of the Core Consultation Document. Rather, identifying any interlinkages will involve a close analysis of any future appeal against the Final Determination and the price control determination as a whole. To the extent that an aspect of a matter raised in a notice of appeal is interlinked to other aspects of the Final Determination it may then be necessary for the CMA (not Ofgem) to decide on the most appropriate way to remedy an error which the CMA decides has been established on a case-by-case basis.[32]

By way of hypothetical example, if Ofgem requires a company to deliver significant improvements in outcomes performance and this company is already at the efficiency frontier (where trade-offs between cost savings and outcomes improvement are inevitable), then clearly the company should be allowed the efficient costs necessary to achieve the improved performance. To the extent that the efficient costs are not allowed, the required level of improvement in outcomes should be reduced accordingly. This is an example where two elements of the price control may need to be considered together to produce a rational result and are, in this sense, "interlinked".

However, it is important to note that the problem highlighted in this example can be remedied by either: (i) allowing the efficient costs of improving outcomes to the required level; or (ii) reducing the required outcomes improvement to a level commensurate with the allowed costs. Thus, while the two elements of the price control are related, the correct result for the overall package can be achieved by adjusting only one of these elements. Furthermore, there would be no obvious need to make any other consequential adjustment to any other aspect of the price control. If the CMA were to accept that Ofgem had made an error in this regard, the error could be remedied in order to correct an inherent imbalance in the price control. Although Ofgem assumes, as it must, that its Final Determination will be a "balanced package", SHE Transmission may not share this view and cannot fairly be asked to set out its position on that issue in advance of the Final Determination. Whether or not the Final Determination is indeed a "balanced package" is a matter that may need to be considered before the CMA in due course and, in that event, it will be for Ofgem to set out its position.

Moreover, seeking to classify the foregoing example as an illustration of a "mechanistic" or "in the round" interlinkage does not shed any light on the issue – the real question is whether an error in a Final Determination has created an imbalance or disconnect between two related aspects of the price control. The focus of the appeal process before the CMA, should it be necessary, is therefore rightly on identifying and appropriately correcting any such errors.

With these preliminary considerations in mind, it will be clear that it is SHE Transmission's position, as articulated elsewhere in this consultation response, that as a result of various errors Ofgem's Draft Determination is seriously imbalanced in numerous respects. Ofgem has failed to find the correct balance between the three "pillars" of the price control (namely: (i) outputs; (ii)

[32] CMA Firmus Energy Determination, para 8.25; CMA SONI Determination, para 13.3; CMA Northern PowerGrid (Northeast) Limited), para. 3.5.1.

expenditure allowances; and (iii) uncertainty and risk mitigation mechanisms, together the ***Pillars***). For example:

a) Outputs/uncertainty mechanism:

i. Ofgem's design of the Volume Driver uncertainty mechanism for Generation and Demand connections is significantly flawed. As a result it has the potential to create an imbalance or disconnect between two related aspects of the price control, namely uncertainty mechanisms and outputs.

ii. In particular, as outlined in response to Core Q22 and the Volume Driver Supplementary Paper, the proposed UCAs outlined in the Draft Determinations documentation are incorrectly calibrated and therefore do not achieve "proportionality" or provide for baseline totex allowances that reflect efficient costs. Based upon SHE-Transmission's historical RIIO-T1 portfolio and RIIO-T1/T2 crossover schemes, this miscalibration would result in a c. £146m under-recovery against costs and therefore loss making.

iii. This will clearly impact on SHE-Transmission's ability to meet targets for associated outputs, such as the timely connections under Standard Licence Condition D16, acceptance of our Environment Action Plan for connections and the customer satisfaction metric under the QoS incentive.

b) Baseline totex/uncertainty mechanism:

i. The uncertainty mechanisms contained within the RIIO-T2 package should complement the baseline totex afforded to each company, serving as a tool for dealing with costs that are genuinely uncertain at the Final Determination stage.

ii. One example where Ofgem's Draft Determinations have failed to strike the correct balance between the use of baseline totex and uncertainty mechanisms is in relation to pre-construction funding for investments that will qualify for assessment under the Large Onshore Transmission Investment (LOTI) uncertainty mechanism.

iii. Pre-construction is vital to demonstrate the need for investment, the comprehensive optioneering, and stakeholder engagement, as well as to ensure delivery is on time and under budget. However, Ofgem proposes that SHE-Transmission incur these costs at risk (even for schemes that SHE-Transmission already knows about) and apply for recovery at close out.

iv. As set out in our response to questions ETQ11 and 12 and associated documentation, this proposal will inappropriately require SHE Transmission to spend £100s million at risk with no resolution being reached until the end-of-period assessment. Uncertainty about future regulatory approval for expenditure will naturally make licensees more cautious about being innovative or proactive in these activities.

v. We are therefore recommending as part of our response to Draft Determinations that Ofgem reinstates pre-construction funding for known projects back in our baseline to make large projects a viable mechanism for delivery of Net Zero projects. We also require in-period adjustments for large strategic schemes that emerge. This can either be through: 1) an annual and end-of-period re-opener or

2) part of the LOTI process on an "as required" basis with an end-of-period review. This will manage both company risk (by providing funding when required) and consumer risk (through the end of period true-up).

c) **Outputs/baseline totex:**

i. Ofgem has also failed to ensure that allowances are set appropriately to cover the costs of meeting efficient outputs in a number of instances. This is evidenced through the acceptance of SHE Transmission's outputs proposed within the Environmental Action Plan (EAP), with provision of baseline allowances in part but not the Closely Associated Indirect (CAI) costs essential to deliver our Sustainability Action Plan. See our response to SHET-Q9.

ii. SHE Transmission's EAP will deliver several environmental commitments including a reduction of embodied carbon in new network build. We agree with Ofgem's proposal to accept the TOs' embodied carbon commitments. To measure and baseline embodied carbon of new projects is an essential first step for reducing the whole life carbon impacts of network infrastructure. However, the cut to the CAI costs will negatively impact our ability to deliver our embodied carbon commitments as this additional work will require input and new processes from our project development and engineering teams.

iii. These CAI also provide for third-party costs for audit, assurance and specialist consultancy. In addition, there are headcount costs associated with the engineering and project management for achieving our science-based targets as set out within the EAP.

iv. Any reduction in baseline totex applied to our Business Plan for CAI costs will negatively impact the ability for SHE Transmission to deliver our commitments set out in our Sustainability Action Plan. We do not believe this is the outcome intended by Ofgem as outputs and other costs for our Sustainability Action Plan have been approved. To ensure outputs are delivered CAI cuts must be reinstated.

v. In addition, as part of the EAP, Ofgem has accepted our ambitious strategy to reduce our Interruption and Insulation Gasses (IIG) leakage rate (i.e. the output). This includes all reasonable measures beyond replacing network assets ahead of need. However, Ofgem has proposed to reject several of our proposed RIIO-T2 schemes that replace badly performing IIG assets (i.e. baseline totex). This is despite SHE Transmission presenting evidence of immediate need. There is also a proposed rejection of monitoring equipment which is essential to us maintaining our IIG leakage performance.

vi. It is clear from the examples provided above, that SHE Transmission is requested to deliver outputs during RIIO-T2 that are not appropriately funded through baseline totex. We therefore do not agree that in all instance's allowances are being appropriately balanced to cover the efficient cost of meeting outputs.

The overall position set out in the Draft Determination is beset by a number of individual errors (including the above examples), the cumulative effect of which is a significantly imbalanced package. Ofgem has no discretion or margin of appreciation in this respect.[33] Rather, the clearly identifiable errors in Ofgem's approach which SHE Transmission has highlighted in its response to the Draft Determination must be corrected in the Final Determination.

SHE Transmission cannot sensibly comment on any potential future notice of appeal against a Final Determination which has not yet been made. However, to the extent that these errors and imbalances remain in Ofgem's Final Determination, SHE Transmission may ask the CMA to correct each and all of them. SHE Transmission does not accept that it is required to investigate, identify and bring to Ofgem and the CMA's attention in its appeal notice any potential interlinkages that do not form part of SHE Transmission's grounds of appeal. This is addressed further in **Section B** below.

Turning next to the examples that Ofgem gives of interlinkages between the different aspects of the price control in certain policy areas, while SHE Transmission agrees that there can be relationships in some of these areas, it would again emphasise that the question must be considered on a case-by-case basis in light of the Final Determination (once made) – not in the abstract. Accordingly, SHE Transmission's position as regards an interlinkages that Ofgem may seek to raise in response to any notice of appeal (whether including the examples it cites in the Draft Determination or otherwise) is fully reserved.

B. The burden of raising interlinkages rests with Ofgem at the response stage

Ofgem proposes in the Draft Determination that it "*would expect that any interlinkages that exist between* [the Pillars]*, including the illustrative examples provided above, are in the first instance raised by an appellant (and wider parties) in the context of any CMA appeal so that each element of our proposed price control determinations is viewed in its proper context*."[34] [emphasis added]

SHE Transmission strongly rejects this suggestion which is contrary to the decisional practice of the CMA:

a) First, while SHE Transmission would of course anticipate explaining in any appeal notice any relationships that are inherent to its grounds of appeal, Ofgem's suggestion that the appellants address "any" possible interlinkages would lead to disproportionate costs being incurred by appellants seeking to pre-empt Ofgem's response on a matter about which Ofgem is best-placed to comment. The fact that Ofgem itself considers that it would *"not be proportionate"* for it to provide an exhaustive list of interlinkages in the Draft Determination underlines the point that the question of interlinkages should only be considered once the appellants' specific grounds of appeal against a future Final Determination are known.
b) Secondly, as the CMA has repeatedly made clear in its decisional practice, "*the question as to whether there are sufficient links between the parts of the Decision which are challenged and parts which are not challenged must be decided on a case-by-case basis taking into account*

[33] In any case, SHE Transmission notes that in any application of regulatory judgement Ofgem must act in accordance with its statutory duty to have regard to the principles that regulatory activities should, amongst other things, be transparent, accountable, and consistent.
[34] Draft Determination, para. 11.25.

the circumstances of each case. <u>Where there are such links, we would, in the first instance, have expected GEMA to have highlighted these and addressed them in its response</u>.[35]" The CMA's expectations of Ofgem in this respect are clear. Ofgem cannot change the CMA's position in its own Draft Determination or otherwise fetter the manner in which the CMA considers this issue (should that be necessary).

c) Thirdly, Ofgem cites the CMA's response to its open letter[36] (the ***Response***) in support of its proposition. However, the Response provides that appellants would be encouraged to explain why the aspects of the decision are wrong having regard to the interlinked aspects of the decision only where such interlinkages have been described "*clearly by the regulator*". The CMA's letter does not therefore support Ofgem's view that the onus is on the appellants, rather than the regulator, to make clear where any relevant interlinkages exist. Moreover, SHE Transmission does not accept that Ofgem's discussion of potential interlinkages as set out in the Draft Determination (or the Final Determination should this discussion be repeated) amounts to a clear description of interlinkages relevant to SHE Transmission's final grounds of appeal. As noted above, the Draft Determination contains only a high level and abstract discussion of potential interlinkages and is therefore of little value. The question can be properly addressed only when any grounds of appeal against a future Final Determination have been formulated.

In conclusion, to the extent that Ofgem wishes to rely on interlinkages (that are not otherwise addressed in the appeal notice) as part of its response to an appeal Ofgem bears the burden of raising such interlinkages in its response.

[35] CMA BGT ED1 Determination, para 3.52; CMA NPg ED1 Determination, para 3.51.

[36] CMA Letter from Andrea Gomes da Silva to Jonathan Brearley, *CMA Response: clarification of our position on Energy Licence Modification Appeals*, 30 October 2019.

***Core Question 40**: Are there other interlinkages within our RIIO-2 package that you think are relevant to the three pillars identified in this chapter?*

In response to Q39, we have outlined a number of cases where Ofgem has failed to achieve the correct balance between the three "pillars" of the price control. To the extent that there are interlinkages within the price control outside of those articulated in our response to Q39, for the reasons explained in that response, these would be a matter for Ofgem to raise on a case-by-case basis in light of the specific flaws identified in grounds of appeal raised in respect of Ofgem's final price control decision. Therefore, SSE reserves its position in the event of any appeal to the CMA in respect of any interlinkages that Ofgem may put forward at that stage.

***Core Question 41**: Do you have any views on our proposal to include a statement of policy in Final Determinations that in appropriate circumstances, we will carry out a post appeals review and potentially revisit wider aspects of RIIO-2 in the event of a successful appeal to the CMA that had material knock on consequences for the price control settlement?*

Please see the response appended at T2BP-DD-SHE-012 - Annex 1 - QA on pre-action correspondence and post-appeal review

***Core Question 42**: Do you have any views on the proposed pre-action correspondence, including on the proposed timing for sending such to Ofgem?*

Please see the response appended at 'T2BP-DD-SHE-012 Annex 1: Q&A on Pre-Action Correspondence and Post Appeal Review'.

***Core Question 43**: Do you think we need specific mechanisms in RIIO-2 to manage the potential longer-term impacts of COVID-19? If yes, what might these mechanisms be?*

We believe that an element of flexibility is paramount throughout RIIO-2 to manage the potential longer-term impacts of COVID-19. In order to work towards addressing these challenges, SHE Transmission puts forward:

- Proposals for dealing with RIIO-T1 outputs impacted by COVID-19 as part of the RIIO-2 Final Determinations. These relate to RIIO-T1 outputs including:
    - Network Output Measures (NOMs)
    - Volume driver
- Given the unprecedented nature of the COVID-19 pandemic, we believe that flexibility - such as that proposed for the output delivery - could also extend to RIIO-2. Although SHE Transmission does not put forward any specific mechanisms for the RIIO-2 period in this response, given the evolving nature of the pandemic, SHE Transmission continues to assess the circumstances in order to keep this under review.

We agree with Ofgem that it is not possible to forecast accurately the final impact of COVID-19 on the ability of companies to deliver against their output targets for the final year of RIIO-1.[37] This in turn results in a level of uncertainty on the knock-on impact this may have when setting RIIO-2 baselines. We have therefore suggested an approach below to minimise the impact or cross-over between RIIO-1 and RIIO-2 which maintains the integrity of each individual price control whilst reducing the regulatory implications for licensees.

Ofgem's recent Open Letter[38] recognised the *'considerable efforts'* made by network companies to lead the way in managing the COVID-19 crisis. It also noted that *'this approach has been critical in setting an example for others to follow'* with networks companies being rightfully praised for strong performance during the first phase of the pandemic. We thank Ofgem for the recognition. The level of due care, attention and planning in response to COVID-19 has been unprecedented and we are proud of our colleagues, contractors and stakeholders alike for the way they have delivered during this period. The close engagement with each has allowed for a positive position under the most exceptional circumstances as we continue to recover from the impact of the pandemic and adapt to new ways of working.

SHE Transmission proposals for RIIO-T1 outputs

We propose that schemes directly impacted by COVID-19 should be 'ring-fenced' and treated as an exception with respect to RIIO-T1 outputs. For the purposes of RIIO-T1 close out, the schemes directly impacted by COVID-19 would be treated as complete. We consider this approach to be in keeping with Ofgem's stated objective of reducing the regulatory burden from the existing RIIO-1 network price controls where it is sensible to do so. This will also reduce the impact on the

[37] Ofgem, Draft Determinations Core Document, paragraph 12.4.
[38] Impact of COVID-19 on network companies – regulatory expectations from 1 July 2020 – published by Ofgem on 16 June 2020

forthcoming RIIO-2 price control and prevent regulatory issues relating to cross-over of schemes which have been impacted by COVID-19.

The two main RIIO-T1 outputs affected as a result of COVID-19 impacts include:

- NOMs: these are a key indicator of asset health used during RIIO-T1. TOs have committed to delivering specific outputs (Network Replacement Outputs) relating to NOMs as specified in SpLC 2M. Ofgem can adjust TOs' revenue upwards or downwards where they have exceeded or failed to deliver outputs and also reward or penalise a TO depending on its justification of performance.

- Volume drivers: the RIIO-T1 volume driver, as specified in SpLC 6F, sets out the baseline allowances and associated generation and capacity outputs. The volume driver mechanism adjusts TOs revenue upwards or downwards depending on whether they exceed or fail to deliver against the capacity outputs, through a unit cost allowance. The current RIIO-T1 Licence allows the recovery of costs for schemes delivering into the first two years of RIIO-T2 (2023). As a result of the consistent and high level of generation connection activity, there will be several load related schemes in delivery at the end of RIIO-T1.

NOMs

Due to the impact of COVID-19, we are likely to experience a delay to the delivery of non-load related schemes which may result in some schemes being delivered after 31 March 2021 (i.e. the end of the RIIO-T1 period). If a network company experiences this outcome as a result of exceptional circumstances, under the current NOMs mechanism this could result in an under-delivery against NOMs output (or a reduced over-delivery). This will impact a TO's assessed performance against its RIIO-T1 targets.

In such cases, the current licence drafting proposes to exclude the cost of the under-delivery from the RIIO-T2 price control allowances which, without the scheme forecast being included within the Business Plan (Dec 2019), would result in work being delivered in RIIO-T2 without any funding during RIIO-T2. **SHE Transmission proposes that schemes impacted by COVID-19 should be 'ring-fenced' and treated as an exception (i.e. completed).**

Not treating RIIO-T1 schemes as complete would also result in a subsequent impact to RIIO-T2 targets. Currently, the RIIO-T1 licence (Special Condition 2M) and the NOMs Reward and Penalty Methodology states, "Cost of under-delivery shall be ***excluded*** from the second price control period allowances". This would result in a reduction to the RIIO-T2 NARMs baseline allowance (which does not include these RIIO-T1 delayed schemes) and an over-delivery against RIIO-T2 outputs, if the TO completes all the work it sets out to complete in its RIIO-T2 Business Plan. This would lead to a shortfall in allowance for the network company against the outputs it is delivering during the period.

This clearly demonstrates a need for Ofgem to address this issue in its RIIO-T2 Final Determination. We propose that the simplest and most transparent way of addressing these RIIO-T1 "exceptions" is to reflect the following in its Final Determinations:

- to ring-fence the outputs and allowances for any RIIO-T1 NOMs schemes which are delayed due to COVID-19[39];
- to capture specific outputs and costs delivered and incurred in RIIO-T2 as RIIO-T1 activity through modified Regulatory Reporting Pack tables; and,
- to allow the companies a period of time to complete the works and avoid the issue of adjusting allowances across price controls and implications of different TIM strengths and possible undue implications for the consumer.

This approach would prevent any implications of COVID-19 delay running into the RIIO-T2 settlement, avoids the RIIO-T2 close out process from dealing with RIIO-T1 projects, allows Ofgem to concentrate on holding network companies to account for delivering their RIIO-T2 outputs, preserves the incentive properties of the RIIO-T1 settlement and avoids any incentive to reduce necessary RIIO-T2 outputs to compensate for delayed RIIO-T1 outputs.

RIIO-T1 volume driver mechanisms

In addition to NOMs/NARMs, Licence condition 6F 'Baseline Generation Connection Outputs and Generation Connections volume driver' requires us to forecast expenditure allowance for the additional Sole and Shared use Generation Connection Capacity to be delivered in the relevant Year and the next three subsequent years, including up to 31st March 2023. This allows TOs to capture the phasing of expected expenditure and allowances in the remaining years of the price control as highlighted in table 4 of the Licence Condition. This information is also used in the Annual Iteration Process to capture forecast revenues.

Key points relating to the volume driver mechanism include that:

- the Licence confirms that the RIIO-T1 volume driver mechanism will provide allowances for schemes that deliver outputs in the first two years of RIIO-T2;
- this approach has been reflected in our annual regulatory reports and allows us to accommodate schemes which straddle the RIIO-T1 and RIIO-T2 price control periods; and,
- this creates the need for appropriate licence terms to allow the continued RIIO-T1 mechanism in parallel with the RIIO-T2 Volume Driver (for new schemes starting in RIIO-T2).

SHE Transmission proposes that the current RIIO-T1 volume driver mechanism should continue for the first two years of RIIO-T2, providing allowances for schemes which have commenced prior to the end of RIIO-T1 and which deliver outputs in the first two years of RIIO-T2 (as is currently the case). This preserves the regulatory decision from RIIO-T1 and is the most efficient and least complicated approach.

In addition, we believe that RIIO-T1 schemes directly impacted by COVID-19 resulting in a delay that will no longer complete within the first two years of RIIO-T2, should be ring-fenced and treated as a RIIO-T1 output (including the RIIO-T1 Unit Cost Allowance).

[39] See email from Steven Findlay (SSE) to networkreports@ofgem.gov.uk attachment '2020-08-10_COVID-19 and SHE Transmission' – Appendix.

This provides a robust mechanism for dealing with schemes that straddle both price control periods, and impacted by COVID-19, and is based on:

- the RIIO-T1 mechanism running concurrently with the proposed RIIO-T2 mechanism – this avoids a cliff edge effect on the allowances for RIIO-T1 schemes and is in line with the current licence provision;
- provision being made in the RIIO-T2 Licence drafting to accommodate the concurrent operation of the mechanisms (i.e. T1 schemes delayed specifically due to COVID-19);
- ongoing flexibility in the management of cross over scheme forecasts to ensure that consumers only pay for the MW or MVA capacity delivered; and
- Extending the approach applicable for schemes which have expenditure commencing in the RIIO-T1 period and delivered before 1 April 2023 to account for those impacted by COVID-19.

As recognised by Ofgem in its June 2020 letter, "*there remains significant uncertainty about the way the relaxation of restrictions affects the work and services undertaken by the network companies*". Therefore, although SHE Transmission does not put forward any specific mechanisms for the RIIO-2 period in this response, we consider that Ofgem will need to continue to take into consideration the heightened level of uncertainty and associated cost that can arise as a result as part of its RIIO-2 price control where appropriate. Given the ever-changing nature of the COVID pandemic, SHE Transmission continues to review the impact that COVID to ensure that we minimise service disruption and continue to mitigate against COVID-19 related impacts wherever we can. Although SHE Transmission agrees with Ofgem that there may be further insights on the impact at the time of the Final Determinations, we expects that there will still be a high degree of uncertainty at that time with respect to predicting the impact of the pandemic. We are committed to continued engagement with Ofgem on this issue as we continue to work together to devise a way through these challenging circumstances in the RIIO-2 period.

3 Electricity Transmission Annex: consultation question responses

***ET Question 1:** Do you agree with our proposals to switch off the incentive in year one of RIIO-ET2 in order to pilot the Quality of Connections survey and develop the baseline targets?*

No, we disagree with the proposal to switch off the incentive in year one (Y1). However, we reluctantly acknowledge this is the only viable option at this stage. We are surprised and disappointed that Ofgem has revisited the opportunity to switch on the Y1 incentive given previous communication[40]. This indicated Ofgem's final position was to run a Pilot in Y1 of RIIO-T2 to gather baseline data for the incentive to begin in Y2, we are surprised Ofgem is, at this late stage revisiting this.

Despite this late reintroduction, we have carefully considered the option to switch on the Y1 incentive using RIIO-T1 data (the annual Stakeholder Satisfaction Survey) alongside the other TOs and Ofgem. We do believe there is value in providing an incentive to encourage TOs to deliver good customer service from the start of the price control. However, we are concerned that the RIIO-T1 data is from a wider stakeholder audience than the proposed Quality of Connections (QoC) and does not fully represent the targeted stakeholder group. This would present uncertainty and risk to SHE Transmission in Y1 and perhaps present a misleading picture to connections customers and wider stakeholders. In this regard, we note that it remains our intention to undertake an annual stakeholder survey on our performance.

A more fundamental risk is that the incentive design and calibration for QoC remains unknown at this point. **We continue to have significant concerns that, at this very late stage in the price control process, Ofgem has not set out a clear proposal for consultation on the design of this incentive.** Ofgem indicated in the SSMD[41] and DD publication (via a comparison to the Gas Networks) that the incentive reward and penalty could be in the region of 0.5% (-/+ 0.5% of base revenue). We proposed in our Business Plan that this should be 1% given the additional work needed to develop the new survey and the level of renewable connections required to meet net zero: whereas the figure proposed by Ofgem appears at odds with the expected focus on connection customers and the resulting level of effort required. The incentive calibration is not contingent on target setting and should have been an area for consultation ahead of final determinations. This lack of confirmation presents an unknown and unquantifiable risk to SHE Transmission which prevents us from proposing the incentive should be switched on from Y1.

In order for these risks to be mitigated an upside only incentive would be the only palatable option until a more informed baseline is set in Y2. Otherwise we agree that a pilot survey is undertaken in Y1 to inform baseline targets for Y2, with the incentive switched on from Y2 only.

[40] Ofgem January 2020 letter to TOs
[41] sections 2.104 and 2.115 of the May 2019 SSMD, Ofgem stated its intention to set the baseline and incentive amount during draft and final determinations

***ET Question 2:** Do you have views on the common milestones, target audience and question of overall satisfaction for the Quality of Connections survey incentive provided in Appendix 2?*

We agree with the proposed milestones, target audience and question of overall satisfaction for the Quality of Connections survey. We have also proposed further development for each TO to consider in their individual methodology statements ahead of the incentive start date for Ofgem's consideration.

The survey was initially a bespoke incentive developed by SHE Transmission and tested with stakeholders during engagement events in 2019.

On review of our proposal Ofgem made the decision to adopt the survey across all three TOs.

As a result, the TOs have collaborated over the last few months to develop a common methodology paper. The paper includes (but is not limited to) refinement of the milestones, development of corresponding trigger points, identification of criteria for the target audience and the overall satisfaction question that are proposed in Appendix 2.

Common milestones

The common milestones in Appendix 2 reflect the key moments that matter for connection customers during the lifecycle of their project/s. Additionally, the TOs have developed corresponding trigger points to ensure timely engagement with connection customers upon reaching each milestone, enabling them to provide real-time feedback on performance.

Target Audience

The target audience covers connection customers that engage with a TO during their project/s and are therefore able to validly comment on that TO's performance based on their direct interactions /experience. We agree this target audience is covered in Ofgem's Annex 2.

Satisfaction Question

The overall satisfaction question has been retained from RIIO-ET1 Stakeholder Satisfaction Survey. Responses to the satisfaction question will be used by Ofgem to determine TO performance on an annual basis against a baseline, as was done in RIIO-ET1.

We agree with Ofgem that the satisfaction question will be asked more frequently, forming the introductory question for each milestone survey, of a subset of the RIIO-T1 survey audience – connection customers.

This means that connection customer responses in RIIO-ET1 could provide comparable data for consideration in RIIO-ET2 baseline setting as previously indicated in paragraph 2.116 of Ofgem's May 2019 Sector Specific Methodology Decision[2].

Further development

The TOs intend to test and refine the common milestones and triggers with our connection customers during our survey development work taking place between now and March 2021. We welcome any feedback received from stakeholders during this consultation in relation to the proposals in Appendix 2. In addition, further development is required to confirm the frequency and collection of data with stakeholders to avoid stakeholder fatigue. Data collection and survey frequency should be clearly set out in each TOs Quality of Connections Methodology Statement ahead of the first year of the incentive being switched on.

***ET Question 3**: Do you think there are any additional KPIs that have not been included in the final NAP which would support monitoring of performance in adherence to the NAP and/or add transparency of the outage planning, management and implementation process for relevant stakeholders?*

No. The NAP KPIs are a result of extensive consultation with stakeholders (see annex: T2BP-DD-SHE-002 SSEN Transmission - Stakeholder Feedback).

The TOs collectively produced and consulted on a set of KPIs to measure the NAP principles of maintaining a safe and reliable network and efficient network access. We also applied previous feedback from stakeholders at OC2 Forums in the KPIs, an example being the KPI to measure how often outages are started within 60mins of the agreed start time. Each GB TO then presented these KPIs to their own stakeholders and feedback was very positive for all TOs.

***ET Question 4**: Do you agree with our proposed LPD mechanisms and do you agree with the criterion that we are proposing to use for our LPD mechanisms?*

Our overarching position is that we fundamentally disagree with the proposed LPD mechanisms and it is our strong view that these proposals should be dropped for the following reasons:

1. *There are already adequate price control mechanisms to deal with the late delivery*

There are existing mechanisms available to address significant project delays and the introduction of any of the newly proposed mechanisms only serves to increase the regulatory burden and costs both for TOs and for Ofgem to manage.

There is an incentive mechanism in place for efficient capital delivery through the Totex Incentive Mechanism (TIM). The (TIM) effectively manages in year variations of phasing, Price Control Deliverables (PCDs) ensure outputs are delivered and for extreme delays enforcement action can be taken.

The TIM effectively manages in year variations of phasing, in scenarios where for example, projects are intentionally deferred or reprofiled but still delivered within the price control period or where the phasing of expenditure is different to allowances. The TIM allows for a true up of revenues for over/under delivery of investments relating to projects which is subject to a Time Value of Money (TVM) adjustment. This ensures that any perceived 'time gains' to the TO are negated.

In the event that projects are intentionally deferred to the next price control, PCDs are in place. As such, any allowance will be returned in full to consumers.

Before replacing these existing mechanisms with something new, Ofgem must consider what issues exist within these mechanisms which would warrant them being replaced or added to. Moreover, rather than replacing the existing mechanisms, a more appropriate approach would be to identify any shortfalls and if any exist, to make adjustments to the existing mechanisms accordingly.

In any case, since all of the issues that Ofgem cites for the introduction of the newly proposed mechanisms are already addressed by the pre-existing mechanisms, there is no basis for the introduction of the new mechanisms for RIIO-2.

2. *The new mechanisms can have a material adverse financial impact*

We have reviewed and assessed the financial impact of each of the three mechanisms. In reviewing them, we identify a number of material issues not fully considered or developed by Ofgem. These include, but are not limited to:

- an increase in the cost of capital;
- a downward pressure on credit rating;
- excessive borrowing costs; and
- the escalation of capital delivery costs.

The financial impact of these mechanisms and impact on consumers needs to be fully evaluated prior to advocating for their inclusion.

We identify that under a range of circumstances costs are likely to increase to consumers as a result of these mechanisms or they have an inappropriate incentive implication.

3. *They may lead to consumer detriment*

Any increase in regulatory penalties to TOs will likely result in risk mitigation from TOs by "contracting out" some of that risk which will increase the cost to the consumer of capital delivery.

It introduces additional risk and pricing in that risk will be passed onto contractors, therefore increasing costs of capital delivery to consumers. This is why an impact assessment is so important.

However, it is also important to note that it will be unlikely we can pass through with a full increase in costs to contractors. There will likely be a tipping point beyond which contractors are not prepared to accept the additional risk.

4. *They are out of step with both proportionate and output-based regulation*

Without prejudice to our forgoing comments, we consider that only in extreme circumstances where a delay can be proven to have had a net adverse impact on consumers (when considering all factors) should any mechanism be levied. Proportionate regulation is output based regulation: under a RIIO Framework, the fundamental question to be answered is whether the outputs being delivered are in alignment with the need of customers, system or securing an efficient outcome (i.e. delivered in the 5 year price control or the agreed time period of a LOTI/SWW project), not if they are delivered slightly later in a price control, particularly as it is efficient management practice to reprofile allowances.

The following paragraphs sets out further details as to why Ofgem's specific proposals are inappropriate.

Reprofiling of Allowances

In many cases the allowance profile is an estimate and is always going to vary year-on-year due to changes in project delivery. Regulatory mechanisms are in place to generate allowances in a set manner such as the Generation Connections Volume Driver and therefore micro-management of these projects as an uncertainty mechanism would be complex and inefficient.

Additionally, the example provided by Ofgem in its workshop on 21 February 2020 is based on a standalone large capital project that is clearly delayed by multiple years. In this case enforcement and other mechanisms are in place to incentivise on time delivery. The £1bn quoted would comprise the entire expenditure of Caithness-Moray, one of the largest individual projects undertaken by a TO during RIIO-T1. This project's allowances varied intentionally from expenditure to support financeability during that period of growth and therefore was to manage financeability concerns and maintain a lower than otherwise cost of capital

As long as projects are delivered within the agreed target dates then any re-profiling undertaken by the TO is a means of managing cash flows and therefore protecting financeability, reducing the cost of borrowing and to keep costs lower for consumers. This is standard treasury management policy and considered best practice across regulated and non-regulated sectors with LCP delivery

In reviewing Ofgem's proposal, we undertook our own assessment[42] and the financial saving is significantly lower if not adverse on consumers under an array of circumstances including increased regulatory burden costs, higher costs of borrowing, and more volatility requiring higher liquidity costs. In evaluating the adverse impact of incentives on TOs, this would encourage TOs to spend in line with their forecast even if inefficient to avoid material changes in revenue and therefore financing costs.

Milestone-based approach

This approach would create a number of cost escalations, including the cost of capital delivery as well as a significant increase in the cost of capital. The incentive on TOs will be to push the risk onto the supply chain and therefore the increase in costs will be factored into their pricing for contract works. Additionally, the delay in revenue is likely to increase the cost of borrowing by downward pressure on credit ratings.

Moody's[43] have repeatedly stated that deferral of revenue is credit negative and therefore puts upward pressure on the cost of borrowing and the cost of equity, both of which will adversely affect customers. The issues of a Milestone-Based approach are well documented during the evidence presented when considering onshore competition in transmission via the Competition Proxy Model (CPM) and Special Purpose Vehicle (SPV). This is consistent with the impact on the Thames Tidway Tunnel (TTT) which has required significant liquidity support and underwriting due to the delay in revenue.

There are also a number of practical implications which we believe have not been sufficiently considered such as:

- How will achievement of the milestone be evidenced? Will it be TO, Ofgem or an external body who decide it has been achieved? If the latter, who pays the external body and how long after notification of milestone achievement should the TO expect payment?

- Who mediates in a situation where the TO considers the milestone to have been achieved and Ofgem do not? Will there be an appeals procedure? Will the TO have to wait until the end of the appeal procedure to be paid?

- How will the potential movement in TO revenue drawdown be reflected in charges to the ESO and subsequent TNUoS payment profiles?

- Will the milestone payment be recovered through the annual RRP or project by project invoicing?

    - If the former, does that mean that if a milestone is achieved just after the RRP submission the TO will have to wait until the following years submission to be paid? This could have the unintended consequence to incentivise TO's to ensure that the projects which have the greatest positive impact on annual cashflow are delivered as a priority.

[42] T2BP-DD-SHE-019 T2BP-DD-SHE-019_ET4_LCP Ofgem Mechanisms-Workings.xlsx

[43] Moody's (2017), 'Rating methodology: Regulated electric and gas networks', 16 March, p. 4.

- If it's the latter this will require a significant uplift in TO back office support as well as regulator resource. Have Ofgem undertaken an impact assessment to conclusively prove that the potential savings made by the consumer of a milestone-based approach out way the certain increased regulatory burden costs?

Project Delay Charge

The use of liquidated damages (LDs) as a mechanism (or for the TOs to manage the risk of a regulatory penalty) is problematic in a number of areas:

- ***Exposure to risk***

LDs are included in construction contracts between the TO and the contractor to pre-determine the level of damages to which the TO is entitled in the event of a delay in delivery. It is market practice for contractors to negotiate the applicable rate of LDs (often expressed as a daily rate) and a financial cap on their aggregate liability for LDs. Typically, we have seen this cap being a maximum of 10% of the contract price which means that even under T1 arrangements TO's have had to carry risk as the daily rate has not been reflective of the totality of losses the TO may incur and the financial cap could be exceeded in the event of a lengthy delay.

The imposition of additional penalties by Ofgem would increase the TO's level of exposure which would be reflected in an increase in risk provision required to build large capital projects. The consequence of this would be that consumers would be unnecessarily exposed to additional costs through risk contingency irrespective of whether the event occurs.

- ***Practical considerations***

It is unclear from Ofgem's proposals as to whether/when a project delay charge would be recovered under the following scenarios, all of which could prejudice the TOs position:

- If the project is delayed but the contractor is insolvent does TO pay the Project Delay Charge if unable to recover LDs from the insolvent contractor? Has Ofgem considered other circumstances in which it would not be appropriate for a Project Delay Charge to be applied? For example, Force Majeure, circumstances beyond the reasonable control of either the TO or the contractor.

- At what point in a project's contractual cycle is Ofgem proposing that the daily rate for the Project Delivery Charge is confirmed in order that this may be passed through to contractors. For example, does Ofgem propose that these additional amounts are confirmed prior to the point TOs tender a contract or at some later point in the contract negotiation? If the latter, at what stage does Ofgem anticipate providing specific amounts in order that these can be included in LD provisions with contractors?

- Where there is a dispute between TO and contractor and LDs are withheld by the contractor, does the TOs liability to pay the Project Delay Charge only arise at the time of payment of LDs by the contractor or does Ofgem anticipate the TO would make payment regardless of whether it had recovered LDs from the contractor?

Furthermore, we would seek clarification from Ofgem on the following;

- Will Ofgem commit to not amending the license conditions for each project once the contract is let even if the circumstances alter the parameters on which the Project Delay would be considered?

- Will it constrain its regulatory discretion in this?

- Will Ofgem confirm that Project Delay charges would replace enforcement and associated penalties? Otherwise is this not a contravention of the concept of double jeopardy?

- Will the additional cost borne by TOs be reflected in uplift to the developer TNUoS?

- In a hypothetical situation, if it were to cost £20m more to finish a project on time for which consumers will foot 50%-85% of the cost, or delay by two months at a cost of £1m, what do consumers want us to do and who decides Ofgem, ESO or developers?

    - This begs the question who is the customer that this policy intends to compensate? Is the payment to the GB consumer or the connecting customer? If the latter, how do we differentiate between infrastructure work and sole / shared use?

    - In the example above, if a decision is made by Ofgem that it is in GB consumers interest to delay the project by 2 months and that delay results in a developer being energised later in the financial year, will that developer be compensated for the increased proportion of its annual revenue being charged as TNUoS?

- ***Impact on Procurement Timescales & Contract Cost***

The scale of the challenge facing the electricity industry to meet net zero targets is one which is well understood, and central to achievement of these ambitions will be the timely delivery of substantial network infrastructure to facilitate the flow of generation from the abundant resources of the north to more southernly population centers.

One of the key enablers of these targets is the use of existing framework agreements with our supply chain. Framework agreements are beneficial as they do not require intensive and costly pre-qualification stages and allow tenders to be concluded in a timely manner. The imposition of additional LD's may cause contractors to seek further negotiation of framework terms and conditions and this could lead to a requirement to undertake a regulated tender resulting in a delay in procurement activities of at least a year and the subsequent delay to delivery of network upgrades would be counterintuitive to the timely delivery of urgently needed reinforcements.

As most developed countries globally strive to meet similar green ambitions, demand far outstrips supply, with a limited number of contractors able to provide the required services. If our projects are required to go to market tender rather than procured through existing frameworks it is highly likely that the same contractor base would submit tenders but with an increased cost from that procured under existing frameworks.

Conclusion

Overall, the imposition these proposed mechanisms will not result in a net benefit for the consumer, the benefit stated by Ofgem for re-profiling of allowances to match expenditure is overstated and an extreme example. If TO's deliver projects through a re-phasing of expenditure compared to allowances, it is likely to lead to a benefit compared to a cost. Only in extreme circumstances where a delay can be proven to have had a net adverse impact on consumers (when considering all factors), should any mechanism be levied.

The introduction of liquidated damages (LDs) as a mechanism is counterintuitive. It introduces an additional cost on contractors by way of pricing in the risk and therefore increasing costs of capital delivery to consumers.

Our strong view remains that there are other mechanisms in place which adequately address the late delivery risk for consumers and these alternatives would not require Ofgem to micro-manage the price control. This would create additional regulatory burden and additional monitoring cost alongside the increased delivery costs. There is no evidence that indicates consumers have been materially affected previously and that this mechanism is warranted.

***ET Question 5:** What are your views on applying our LPD mechanisms to some or all of the projects identified at paragraph 2.74?*

In response to ET Q4, we have summarised the adverse implications and lack of impact assessment undertaken on each option and in particular the increase in costs to consumers of each mechanism to varying extents. At this stage, there is no evidence that these mechanisms are required or that existing mechanisms do not provide adequate protection to consumers from any detriment. Imposition of these proposals would require micro-management of the price control and likely lead to significantly higher costs of management and monitoring of the regulatory framework.

Before any LPD mechanism is to be applied to some or all of the projects identified in paragraph 2.74, we would seek evidence of:

- Consumer detriment in Transmission; evidence that indicates consumers have been materially affected previously and are at risk of such losses in the future.
- A gap analysis; anything in the regulatory framework that does not address any potential consumer detriment.
- An impact assessment of proposed additional mechanisms.
- Ofgem's proposed methodology to value the detriment to consumers.

With specific reference to the projects identified in paragraph 2.74, we draw Ofgem's attention to two key considerations.

It is highly likely that tenders will have been issued for the majority of works within these projects at the point of final determination publication (i.e. within T1). Trying to introduce a new commercial term such as additional LDs at a late stage in negotiations is likely to have a cost impact and if preferred bidders are already confirmed, our commercial leverage is likely to be much less than if inserted at the stage where the process was competitive.

A number of these projects will be procured under existing framework arrangements and as noted in our response to E QT4, the imposition of additional LD's may cause contractors to seek further negotiation of framework terms and conditions and this could lead to a requirement to undertake a regulated tender resulting in a delay in procurement activities and an inevitable increase in contract costs.

Conclusion

We have highlighted in our response to ET Q4 that the increase in delivery costs, higher cost of capital through financeability pressures, and the adverse incentives are materially negative for consumers for either mechanism.

Only in extreme circumstances where a delay can be proven to have had a net adverse impact on consumers (when considering all factors) should any mechanism be levied. In the absence of evidence that an existing mechanism does not already address any of these issues, there are no merits that justify their introduction for RIIO-2.

***ET Question 6**: What are your views on our consultation position for the three electricity TOs' EAP proposals in RIIO-2 as set out in this document?*

In principle, we support Ofgem's Environmental Action Plan (EAP) proposal to "*accept all of the TOs' proposals with the following conditions or revisions for specific areas* (p30 ET)". We have provided feedback on each of Ofgem's EAP decisions in the response below (see Section 1).

However as noted in Section 2, **we disagree with the three following areas** that are described in full in our response below.

Our Environmental and Sustainability ambition has not been recognised in our Consumer Value Proposition (CVP) for the Business Plan incentive. This is despite leadership in a number of areas as verified by our independent benchmarking and showing leadership in RIIO-T1 in both EDR and the SF6 ODI.

There are several Ofgem EAP decisions noted below that require a consistent approach to ensure a just transition for our customers, consumers and stakeholders and ensure parity across network regions:

- IIG Leakage incentive - a proportionate yet challenging approach to reducing IIG leakage
- SF6 asset replacement
- Baseline allowances for community funds, which if granted on a locational basis benefits those primarily in a TO's network area, creating unequal opportunities across network areas.
- Environmental Scorecard Incentive (ODI-F)

Baseline allowances have been provided in part for the EAP proposals but not the Closely Associated Indirect costs (people) essential to deliver our Sustainability Action Plan. See our response to SHET-Q9.

<u>**Section 1 Feedback on EAP decisions**</u>

EAP Output: We support Ofgem's proposals that EAP commitments are captured under the reputational incentive of the Annual Environment Report (EAP) as noted in paragraph 2.84 of the ET annex:

"We propose to include the funding for the EAP commitments covered in this section in the respective TO's baseline allowance without specifying PCDs. This is because the amounts for individual EAP commitments are not material enough to warrant a PCD, and we consider that the reputational incentive of the AER is a sufficient safeguard to mitigate the risk that a TO does not deliver on an EAP commitment (p31)".

However, please also refer to SHET-Q3 response and Section 2.2.4 below on the requirement for a consistent approach for an Environmental Scorecard Incentive (ODI-F).

Science-based targets (SBT): we agree with the proposal to set a common ODI-R for the TOs' SBTs in order to harmonise the output classification.

It is understood that Ofgem's minimum requirement for a SBT is a target along the 2-degree pathway, as explained at Ofgem's Transmission Owners Workshop on Draft Determinations on the

27/07/2020. This should be clearly stated in Final Determinations. In this context, it is important to note that SHE Transmission have set and had approved the world's first Science based target for an electricity networks company at the 1.5-degree pathway - going beyond the minimum requirement (refer to SHET-Q4 that our SBT ambition has not been recognised in our CVP and there is a need for a consistent Environmental Score Card incentive (ODI-F) as described below).

Reducing emissions from building energy use: we support Ofgem's proposal to **"**approve the baseline funding request by SPT and SHET relating to this commitment subject to both companies providing further detail of their planned interventions. This is because we expect that the planned interventions would be economic overall given the results of several recent trials (2.91)" (p33).

As noted in our Sustainability Action plan (p37), we will build on the Napier University study Research Study (2018) *Reducing energy losses and greenhouse gas emissions from substations* and will undertake further technical reviews of the suitability of existing substations for energy efficiency measures and PV (Short term - 2021/22).

We will work with Ofgem on the content and timeline for providing further information on the substation intervention programme in relation to our project timeline. It is important to note that as this programme of works will be contingent on the delivery of our load and non-load schemes, we will not be in a position to provide a finalised delivery plan ahead of settlement of the allowed costs and outputs for RIIO-T2. Please refer to page 40 of our Sustainability Action plan whereby we committed to transparently report on the progress of these interventions with relevant KPIs proposed.

It is also worth noting that all of SHE Transmission Offices and depots are already supplied by 100% renewable electricity from July 2019.

Emissions from operational and business transport: We agree with Ofgem's position that, "energy networks have a role to play in facilitating the decarbonisation of transport, as well as leading by example to convert their own fleets to EV/AFVs. Converting their fleet to EV will also encourage the networks to be proactive with industry in addressing network-related issues that might otherwise hinder the wider rollout of EV/AFVs (p34)".

Reducing embodied carbon in new network build: We agree with Ofgem's proposal to accept the TOs' embodied carbon commitments, without amendment, to measure and baseline embodied carbon of new projects as an essential first step for reducing the whole life carbon impacts of network infrastructure. However, please note the cut to the Closely Associated Indirect costs described in Section 2.3 below will negatively impact our ability to deliver our embodied carbon commitments, as this additional work will require input and new processes from our project development and engineering teams.

It is noted that Ofgem encourage both SHE Transmission and SPT to strengthen their ambitions in this area by setting a target for reducing the amount of carbon embedded in new infrastructure during the course of RIIO-2. We believe our ambition is already strong and rigorous. Setting targets is contingent on being able to consistently and transparently measure embodied carbon and then target actions on the parties responsible at source for the carbon – this is our approach.

There is currently no industry recognised methodology for accounting and reporting on embodied carbon. A critical first step is to develop an industry methodology for accounting for embodied carbon that will involve engaging with a wide range of stakeholders, including industry representative bodies, regulators, infrastructure providers and suppliers, to develop a consistent industry-wide approach for measuring and reporting on embodied carbon which is aligned with the latest carbon science.

An additional challenge in reducing the embodied carbon of goods is that they are inherently dependent on a reduction in the carbon intensity of manufacturing, assembly and transportation processes which will vary depending on the country of origin. Due to the complexities of reducing emissions from imported materials, caution is needed around encouraging offsetting approaches rather than in-setting or actual emission removals, due to the associated cost differential of these measures.

Alongside the inclusion of embodied carbon reporting in our CBA framework, SHE Transmission has set a sector leading scope 3 GHG target for our science-based target: We committed to work closely with its supply chain so that two thirds (67%) of its suppliers by spend will have a science-based target by 2025.

Working collaboratively with our suppliers to set their own Science based targets will seek to tackle embodied carbon in our supply chains where there is greatest influence.

Proposals for electricity losses from the transmission network: We agree with Ofgem's position to accept our Transmission losses strategy without amendment.

We also welcome and agree with Ofgem's position that losses are largely the result of energy flows and loading on the system that the ESO controls: "*Having considered it further, we do not think it is appropriate to emphasise loss minimisation in a Licence condition for the TOs. This is because transmission losses are largely the result of the energy flows and loading on the system, which the ESO controls. The TOs have a partial influence on transmission losses through decisions they make on asset procurement and network design. We think that a Licence condition to minimise losses could give undue weight to reducing losses in network investment decisions over factors such as cost and system need, which are important considerations to ensure that any proposed investment is economic and efficient*" (p38).

As an update from SHE Transmission, during the development of our science-based target we have now set a scope 3 GHG Transmission Losses intensity target as follows: *Commitment to reduce Scope 3 Transmission Losses GHG emissions 50% per* gCO_{2e} *from losses/kWh by FY2029/2030 from a 2018 base year* that has been approved and validated by the science-based target initiative.

Embedding circular economy principles and improving supply chain sustainability: We agree with Ofgem's proposal to accept the commitments that the TOs have made for the circular economy and improving supply chain sustainability.

It is disappointing that our supply chain commitments included in Sustainability Action Plan Section 8 (p97-100, draft supplier code) have not been recognised by Ofgem. These requirements, that are now being integrated into our RIIO-T2 procurement frameworks, raise the bar for supply chain sustainability requirements. In particular, our scope 3 GHG target commitments of "*two thirds (67%) of its suppliers by spend will have a science-based target by 2025*" is expected to drive improvement across our supply chains.

We also want to highlight that the SSE Group procurement function have undertaken a gap analysis against ISO20400 and over 2020/21 will develop and deliver its new sustainable procurement strategy, designed to deliver the recommendations of the gap analysis and embed sustainability considerations through every stage of SSE's procurement process.

Enhancing biodiversity and natural capital: Refer to question SHET-Q5 whereby **we agree in part** with the Ofgem's proposals on our CVP for Biodiversity. We fully **support** the proposal to approve the CVP as it clearly goes above and beyond the minimum requirements set by Ofgem. However, we have **strong concerns** relating to any proposal that would look to re-quantify the value to the consumer away from our proposed approach.

Reducing pollution to the local environment: We agree with Ofgem's proposal to accept the TO's proposals for removing polychlorinated biphenyl (PCBs) by 2025 on the network and its determination as follows:

"We have assessed the proposed works to remove all equipment from the transmission network containing PCBs and are satisfied that the relevant engineering interventions would be required to comply with all relevant requirements. We also consider that the proposed expenditure to be efficient (p41)"

It is important to note that we also included plans for noise management in our Sustainability Action plan on page 60-61; this is an important issue for our stakeholders as well as local planning and environmental authorities. As refenced in SHET-Q7 we disagree with Ofgem's decision to remove the cost premium applied for a lower noise model transformer proposed on our Sloy project (T2BP-EJP-0027).

Enhancing biodiversity and natural capital: Refer to question SHET-Q5 whereby **we agree in part** with the Ofgem's proposals on our CVP for Biodiversity. We fully **support** the proposal to approve the CVP as it clearly goes above and beyond the minimum requirements set by Ofgem. However, we have **strong concerns** relating to any proposal that would look to re-quantify the value to the consumer away from our proposed approach without further consultation.

Sustainable resource use, recycling and waste reduction: We agree with Ofgem's proposal to accept the TOs proposals for sustainable resource use, recycling and waste. As noted above we support Ofgem's proposals that EAP commitments are captured under the reputational incentive of the Annual Environment Report (EAP) rather than a PCD.

<u>**Section 2 – we disagree with the three following areas:**</u>

2.1 Our Environmental and Sustainability Ambition has not been recognised in our Consumer Value Proposition.

Please refer to SHET Q4.

2.2 A consistent approach is required for EAP decisions to ensure a just transition for our customers, consumers and stakeholders and ensure parity across network regions

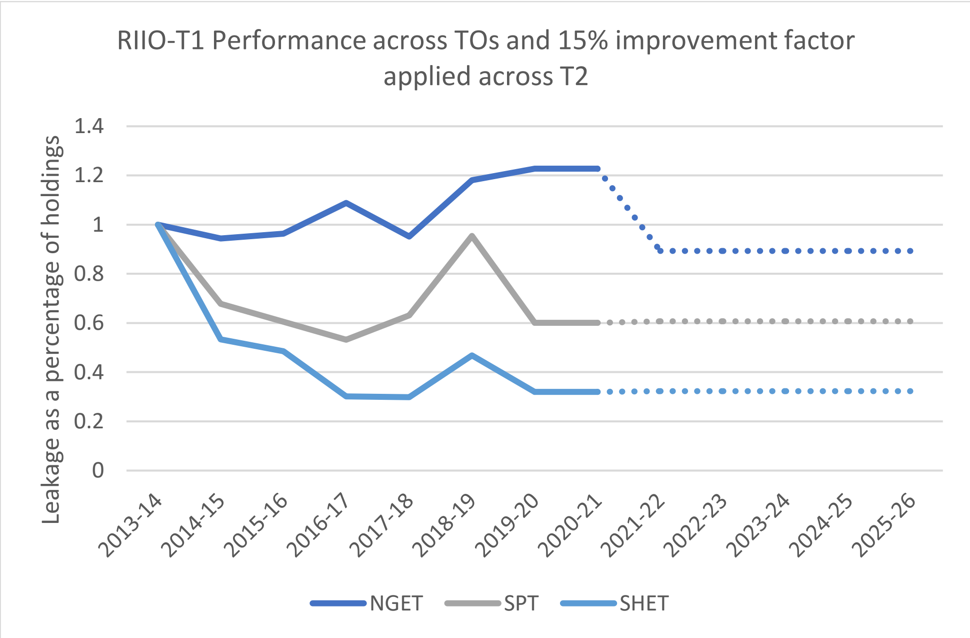
2.2.1. Insulation and Interruption Gasses (IIG) leakage incentive - a proportionate yet challenging approach to reducing IIG leakage

We welcome Ofgem's decision to approve our IIG Strategy without amendment. However, we do not believe the proposed methodology for the IIG leakage incentive drives or awards the right behaviours required to reduce IIG leakage. We also think the incentive is wrongly calibrated in that it may punish the TO with the lowest leakage rate as a result of strong performance during RIIO-T1.

RIIO-T1 performance

As explained in SQ 26[44] we have been the **strongest performer in the RIIO-T1 incentive amongst the TOs illustrated in Figure 1 below**. We are also the only TO to be awarded the incentive **for year on year improvement** (whilst in comparison other TOs were rewarded when performance has been poorer than previous years). We have a track record of strong performance from both TPCR4 and RIIO-T1 due to our innovative and ambitious improvements driven by the SF6 Incentive (see our response to SQ 26). This has been demonstrated by Ofgem analysis[45] that SHE Transmission have made a 60% improvement to performance.

ET Q6 Figure 1: TO comparison of RIIO-T1 performance and proposed RIIO-T2 targets



[44] Please see SHETL_SQ_POL_26
[45] See Ofgem DDQ374 SF6 Targets for RIIO-T2

RIIO-T2 targets

We welcome Ofgem's proposal to baseline the RIIO-T2 incentive on the average performance from years 2013/14-2019/20 following our feedback. However, we **strongly disagree** with the additional uniform 15% improvement factor applied. **We believe this disproportionately punishes our strong performance during RIIO-T1 and this approach of a uniform 15% improvement across the TOs is flawed. See Figure 1 above.** The 15% improvement factor **lacks justification**[46], nor had any stakeholder, including TO, consultation. An appropriately calibrated stretch target should recognise the different starting points (relative performance) of licensees and have the goal of 'closing the gap' between the worst and best performer.

The room for further improvement is less when you are already the strongest performer. Applying Ofgem's proposals against our internal views of potential outturn we believe there is a high likelihood we will be in a penalty position because of a tight baseline as a result of our RIIO-T1's strong performance (see annex T2BP-DD-SHE-007 ET Q6 Annex 1 SSEN Transmission IIG ODI Draft Determinations Impact Assessment). We believe this to be **unrealistic** and **not** the '*challenging yet achievable target*' as intended by Ofgem and expected by stakeholders. This creates the potentially perverse outcome, whereby we could be the best performing licensee (measured by % leakage), yet appear to be the worst performing as we incur penalties under the incentive.

We are the **world's first network company to have an approved SBT** to reduce our own emissions in line with 1.5-degree pathway. This aligns with our ambitious target to reduce our own GHG emissions by 1/3 by the end of RIIO-T2. A large proportion of our GHG emissions is caused by SF6 (see response to SQ 30) and we have put forward an **ambitious strategy to reduce our leakage rate**. This includes all reasonable measures beyond replacing ahead of need (see SQ 30). We would welcome sight of the analysis that Ofgem has undertaken to set the 15% uniform stretch target and, specifically, the actions it believes are available to us as the leading performer to cost effectively achieve that target.

We are not shying away from improving our IIG leakage performance in RIIO-T2 and believe that leading performance should be rewarded. Due to the growth in our network and increase in assets there is a higher chance of a single leak skewing our performance. Due to our network growth, this likelihood will increase during RIIO-T2. The reputational damage to SHE Transmission of receiving a penalty in this incentive, when possibly having the lowest leakage rate amongst TOs and performing under manufacturer's guarantees of 0.5%, is disproportionate.

Alternative proposal

We urge Ofgem to ensure there is both **parity across TOs and consider re-adjusting the IIG incentive to a similar approach to ENS**. The IIG incentive should not punish strong performers in RIIO-T1 via unrealistic baseline targets. We believe a 0.38% leakage rate for SHE Transmission is reasonable because:

[46] Ofgem's Sector Specific methodology Decision section 3.165 set out three options for consultation on the IIG leakage incentive. However, this does not include the proposals by Ofgem.

We have already made a **step change** in performance during RIIO-T1. A 0.38% as a baseline for RIIO-T2 remains challenging for SHE Transmission. This is due to the increase in assets, increased monitoring and higher likelihood that one leak could skew our performance.

The reputational and financial damage of a penalty if SHE Transmission does not reach 0.38% is **significant** to drive the continuous improvement behaviours required for RIIO-T2.

We will continue to strive towards a **reduced leakage rate** in line with our SBT. This is outlined in our SBT CVP (see SHET-Q4).

To encourage strong performance across the TOs, Ofgem should consider an approach similar to ENS. No blanket improvement factor has been applied to RIIO-T2 ENS targets, rather targets are weighted based on each individual TO's past performance. The ENS incentive is evidence of the success of this approach, with each licensee demonstrating ongoing improvement.

We believe the above is **challenging yet achievable** for SHE Transmission as intended by Ofgem and expected by stakeholders.

2.2.2 SF6 asset replacement - replacement of badly performing assets

RIIO-T2 certain view schemes - need identified <u>ahead</u> of RIIO-T2

We note Ofgem's draft decision to allow a PCD for NGET to replace 'leaky assets' ahead of need. However, Ofgem has proposed to reject a number of our RIIO-T2 schemes that replace badly performing IIG assets despite us presenting evidence of need now. There is also a proposed rejection of monitoring equipment which is essential to us maintaining our IIG leakage performance. Ofgem's conclusions appear inconsistent and we urge reconsideration of:

<u>Broadford (T2BP-EJP-0027)</u> – this scheme is to replace a single 132kV circuit breaker that is from a family type that has performed very poorly in the past, both in SHE Transmission and on other transmission and distribution networks. While this specific breaker (Broadford 305) has not exhibited substantial leaks to date SHE Transmission's experience of this type of breaker is not positive due to previous leakage issues, and we consider them to be inherently unreliable as evidenced by removal of seven more breakers of this type during RIIO-T1.

<u>St Fergus Mobil (T2BP-EJP-0044)</u> – this scheme is to replace two 132kV circuit breakers that have both had significant issues with SF_6 leakage in the RIIO-T1 period – 8.1kg of gas has been pumped into the circuit breakers which contain only 5kg of gas each. Other circuit breakers of the same type have also exhibited SF_6 leakage and are targeted for replacement in T2 (8 x 132kV circuit breakers at Beauly).

<u>ICPM (T2BP-EJP-0012)</u> – this paper justified funding to install condition monitoring equipment on assets which included SF_6 monitoring on switchgear to help reduce gas emissions.

These justification papers have been amended to respond to Ofgem's feedback and submitted as part of our response.

It is also noted that cost premiums applied for SF6 alternative switchgear on our Willowdale (**<u>T2BP-EJP-0031</u>**) and Glenshero (**<u>T2BP-EJP-0024</u>**) projects have been cut which will jeopardise the potential to install SF6 alternatives on these projects and meet our carbon targets. Please refer to SHET-Q7 and SHET-Q6 respectively.

Replacement need identified <u>during</u> RIIO-T2

In order for SHE Transmission to continue improving performance, below manufacturer's guarantees, we believe a **similar Uncertainty Mechanism** to the one proposed by NGET (which is now proposed as a PCD) should be applied consistently to all TOs. This is because the NARMS methodology does not recognise any benefit for the intervention on **non-lead assets** (the relevant asset here being Gas Insulated busbars (GIB)) to be replaced due to poor leakage performance. For example, for SHE Transmission this could apply to 11 substations with GIB, which if they performed poorly over the RIIO-T2 period, we would be unable to replace under NARMs as the proposed NARM Funding Adjustment would not increase our funding for a justified over-delivery of a non-lead asset. This is a gap in the current framework which applies to non-lead assets, please see NARMS SQ3 response for further detail.

In addition, replacing badly performing **lead** IIG assets (such as GIS circuit breakers) is one of the examples in which TO's are incentivised to ignore the needs of customers and essentially 'stay-the-course' of the Business Plan under any circumstances regardless of evidence to the contrary. This is clearly flawed. This could also result in a double penalty. A penalty under the IIG incentive for the asset's leakage and a penalty under the NARMS proposed funding adjustments. Please see our response to SHET NARM Q3 for further detail.

2.2.3 Baseline allowances for community funds

It is noted that Ofgem has proposed to accept SPT's bespoke PCD for a £20m Net Zero Fund, on a use-it-or-lose-it basis (Draft Determinations – SPT Annex, p23).

The SPT RIIO-T2 Business Plan explains the purpose of the funds is a follows: "For RIIO-T2 we have proposed a £20m 'Net Zero' fund so that we can use our central and impartial role within the energy system to ensure local communities, including those identified as 'vulnerable' are financially supported to maximise the social, environmental and economic benefits of local energy solutions. The Net Zero fund will focus on facilitating practical, low carbon initiatives with tangible outcomes that benefit local communities and help Britain on path to Net Zero. This fund builds on our existing green economy fund…(p46)"

If similar community fund support is not provided to SHE Transmission then there will be **a disconnect, with communities in south** Scotland having access to funding that isn't available in the North that **could prevent a Just Transition to the low carbon economy.**

To ensure parity across the network regions we therefore **request an equivalate community fund on a use-it or lose it basis** for our network region that we will co-design with our stakeholders to ensure it meets the needs of local communities in our network regions.

In our Sustainability Plan we committed to, "*Work with our stakeholders to determine how we can best provide additional support to community initiatives (2021/22)" (p82).* We would therefore request the funds once the community fund has been designed with our stakeholders following the first year of RIIO-T2 (2022).

It is important to note that SHE Transmission and the wider SSE Group have a wealth of experience in managing community funds. The SSE group has an in-house community funds team which **has ten years of experiencing in delivering all of SSE's funds.**

Over RIIO-T1, SHE Transmission has provided additional support to communities across our network area through the SSEN Resilient Communities Fund. This fund is used to support projects that will help communities during extreme weather events or when electricity supply is lost, with a focus on vulnerable consumers (www.ssen.co.uk/RCF/). As at the end of 2018/2019 this fund has awarded £2.45m to 362 local projects.

Furthermore, in 2018/2019 the SSE Renewables Community Investment programme invested £6.6m in 413 community projects.

(https://www.sserenewables.com/media/hzaph2m3/ci-report_2019_finaldraft3.pdf).

We would look to design a new community fund with stakeholders including any lessons that can be learned from the industry and SPT's green economy fund.

Initial Stakeholder feedback: We have undertaken initial stakeholder engagement with a targeted group of relevant stakeholders for their views on Ofgem's RIIO-T2 Draft Determination on community funds.

There was strong agreement from our stakeholders that Ofgem should apply a consistent approach to community funds, ensure parity across network regions and approve a community fund for our network area given Ofgem's proposal to approve SPT's Net Zero fund.

It was highlighted that allowing SHE Transmission a similar community fund would avoid disadvantaging one region of Scotland over another. Early feedback suggested that such a fund should focus on vulnerable consumers, with an emphasis on fuel poverty.

It was noted that the development of a community fund for our network region would require further stakeholder engagement over the coming year to ensure it is stakeholder-led and has the right scope and focus to benefit local communities in the north of Scotland.

2.2.4. Environmental Scorecard Incentive (ODI-F)

It is understood that Ofgem has proposed "to accept NGET's proposal for an ODI-F environmental scorecard. Subject to resolving the issues discussed in paragraphs 2.15 to 2.18" (Draft Determinations – NGET Annex, p15),

There is an opportunity for a common Environmental Incentive (ODI-F) for all TOs with appropriate targets. SHE Transmission has similar baseline data and options to propose target for each of the areas proposed in National Grid Transmission's Environmental Scorecard ODI-F as summarised below. This would be largely based on targets already set out in our Business Plan and developed through consultation with stakeholders.

ET Q6 Table 1

NGET Bespoke Environment Scorecard ODI-F	SHET Position
1. Percentage of our fleet that is alternative fuel vehicles <68%	Similar targets NGET have baselined £26.7m (vehicles and charging infrastructure). SPT have baselined £0.8m (charging infrastructure). SHE-T have baselined £2.7m (charging infrastructure).
2. Percentage reduction in carbon emissions from our business mileage <14%	Baseline data - could set appropriate targets
3. Percentage of our operational and office waste that is recycled <70%	Baseline data – waste targets set
4. Percentage reduction in the waste we create at our offices <30%	Baseline data this year – could set appropriate targets
5. Percentage reduction in water use for our main offices <30%	Baseline data – could set appropriate targets
6. Percentage increase in the environmental value of our non-operational land <14%	Note - National Grid CVP proposal.
7. Percentage net gain on all construction projects <20%	SHET CVP proposal. Propose replacement with another KPI.

We are open to working with Ofgem and our stakeholders to set appropriate yearly incentive targets around our overall environmental targets.

A common environmental scorecard incentive (ODI-F) will:

- Encourage the right behaviour to focus on environmental improvement
- Hold us to account for delivery against targets (reward and penalty)
- Incentivise improvement ahead of EAP targets
- Create competition amongst TOs on performance of EAP targets

Initial Stakeholder feedback: We have undertaken initial stakeholder engagement with a targeted group of relevant stakeholders for their views on Ofgem's RIIO-T2 Draft Determination on an Environmental Incentive (ODI-F).

We continue to receive strong feedback that we should be ambitious and that appropriate mechanisms should be in place to drive and encourage the right behaviours. One specific stakeholder highlighted that, where appropriate and practical, the mechanisms across TOs should be similar and that Environmental Discretionary Reward (EDR) had driven the right behaviours during RIIO-T1.

Many of our stakeholders did not feel they had appropriate expertise to provide initial comment on the regulatory mechanism for the environmental scorecard but were open to further and more in-depth engagement on the design of environmental incentive over the coming months.

2.3 Baseline allowances have been provided for the EAP proposals but not the Closely Associated Indirect costs (people) to deliver our Sustainability Action Plan.

As noted in our Sustainability Action Plan Annex 4 'Costs of these proposals' and our SQ response SHETL_SQ_POL_42, there are Closely Associated Indirect costs (CAI) associated with the delivery, assurance and reporting of our Sustainability Action Plan.

These CAI costs are largely internal employees' headcount, along with third party costs for audit, assurance and specialist consultancy. For example, there are headcount costs associated with the Engineering and project management for achieving our science-based targets.

It important to note that any cost cut in our Business Plan for Closely Associated Indirect costs will negatively impact the ability for SHE Transmission to deliver our commitments set out in our Sustainability Action Plan. We do not believe this is the outcome intended by Ofgem, as outputs and other costs for our Sustainability Action Plan have been approved. To ensure outputs are delivered, CAI cuts must be reinstated. Please see our response to SHET-Q10.

ET Question 7: *What are your views on our consultation position for setting the expenditure cap for visual amenity mitigation projects in RIIO-2?*

We fully support Ofgem's proposals to fund visual amenity projects for RIIO-T2 through a similar methodology to RIIO-T1. Whilst our stakeholders have identified potential to extend this scheme beyond National Parks and National Scenic Areas in the future, we accept there is further engagement work required to understand the wider appetite for this and to develop a clear methodology for its implementation. We will seek to do this during RIIO-T2 for potential application within RIIO-T3.

We also fully support Ofgem's proposal to allocate 2.5% of the expenditure cap to each TO (7.5% of the total expenditure cap for the TO's combined) for landscaping and other measures that do not involve significant changes to transmission infrastructure. It is our understanding that these projects will not be subject to individual Ofgem approval but will follow our existing internal governance process, following which they will be reported on annually as part of our regulatory reporting process. Assuming this is the case, we believe this will help to significantly expedite smaller value projects that can be delivered quickly to benefit local communities.

In relation to the overall expenditure cap, **we object to Option 3 as it stands**. Whilst we agree with the principle that any projects put forward should satisfy the tests of minimising high importance visual impacts at an affordable cost to the consumer, it is not clear in the Draft Determination how the reduced total has been calculated. **Until this clarity is provided think that Option 2 must be maintained for the expenditure cap** to ensure that our stakeholder led proposals are able to be delivered.

Option 2 identifies the delivery cost of all proposals put forward in the respective Business Plans (plus 2.5% per TO for landscape schemes) at £725m. However, Option 3 reduces this figure to £465m with no information provided on which projects the £465m is based on. Without such clarity is it difficult to confirm whether the option meets both our and our stakeholder expectations for the scheme and what proportion of the fund is expected to be allocated to projects within the SHE Transmission area.

Option 3 states that the fund will cover those potential pipeline projects identified in the Business plans. As we set out in our Business Plan (Our Visual Impact of Scottish Transmission Assets (VISTA) - Our Approach for RIIO-T2, December 2019) we have indicatively identified projects that we believe have potential to be developed. We do however expect there to be others that are identified/prioritised during our stakeholder informed validation review that also meet the objectives of the scheme. We seek reassurance that such schemes will be eligible to apply.

As projects will take different lengths of time to develop and refine, we believe there should be a mechanism to ring fence TO fund allocations for a set period within the price control to ensure one or two large projects in another TO area do not utilise the entire fund prior to applications being submitted by others.

We believe these should be clarified in the Final Determination to provide sufficient confidence that funds will be allocated fairly across GB.

***ET Question 8**: Do you have any views on our outputs that have not been covered through any of the specific consultation questions set out elsewhere in this chapter? If so, please set them out, making clear which output you are referring to.*

This response covers the following outputs not covered elsewhere: ENS and Timely Connections.

Energy Not Supplied (ENS)

We remain concerned at several Ofgem's proposals in relation to ENS, specifically:

- The timelines associated with submitting an updated ENS Methodology Statement;
- Potential revisions to the Value of Lost Load (VoLL) during RIIO-2; and
- Ofgem's proposal to progress with a 3% collar.

ENS Methodology Statement

The proposal to submit an updated ENS Methodology Statement before 31 December 2020 is too ambitious and must be extended to allow for proper review following publication of the Final Determinations and licence conditions. In addition to an overall review, Ofgem also expect TO's to include 'tangible commitments (including milestones and key deliverables)' to develop a methodology that takes account of embedded generation in the ENS metric.

The ability to establish the level of granularity Ofgem is proposing and including milestones and key deliverables is unreasonable in terms of timescale and impractical in terms of timing as the relevant licence conditions will not be formalised by the 31 December 2020. In addition, the ENS Methodology Statement is jointly prepared by all TOs, seeking consultation with other stakeholders (for example, the ESO and DNOs), and will require co-ordination and agreement. It is unreasonable to expect TOs to complete before 31 December 2020 and we would advocate extending this to the end of Q2 2021 (or later, subject to final direction of the licence conditions).

In addition, Ofgem propose to establish an industry working group to develop a methodology, including any necessary assumptions, for accounting for embedded generation in RIIO-T3. We do not believe the scope of the working group should be limited to considering values of embedded generation as the only solution to provide an effective measure of reliability. We would also note Ofgem's recent Call for Evidence on the visibility of distributed generation connected to the GB distribution networks[47]. This work, along with industry reforms associated with DSO (including access rights) will invariably impact on our ability to determine timescales and commitments for including embedded generation within the ENS metric. Any revisions to the ENS methodology should take due account of the commercial access agreed with each customer as this is the basis of network investment.

The timeline should be extended to allow sufficient opportunity for a robust and comprehensive review of Ofgem's findings to be undertaken and incorporated within the commitments included within the ENS Methodology Statement. We are open to further discussion with Ofgem as to what

[47] https://www.ofgem.gov.uk/publications-and-updates/call-evidence-visibility-distributed-generation-connected-gb-distribution-networks

a reasonable timeline would look like. More so the purpose of this review should be clearly determined upfront on consultation with affected stakeholders.

Value of Lost Load (VoLL)

Ofgem is proposing to provide flexibility within the licence to amend the VoLL value during RIIO-2. The current evidence Ofgem refers to within the Table 3, page 13 of the Draft Determinations Electricity Transmission Annex suggests that significant changes from the current VoLL value is required. Ofgem previously stated it would carry out a revised VoLL study ahead of RIIO-T2. We are disappointed it has failed to do so. We disagree with the proposal that VoLL should be amended during a price control. It re-opens the incentive package causing uncertainty for consumers and investors, as well as the network companies. This goes against the certainty of the price control settlement.

At a minimum any change to VoLL should be consulted on as part of the draft and Final Determinations and set for the full period. It is possible, that as we transition towards the use of electricity for transport and heat, the VoLL could increase due to the increasing importance of a reliable electricity supply. If Ofgem insist on the ability to change VoLL in the period, the licence condition should allow for only one change and should limit the amount of change (e.g. plus or minus 20%). Again, providing network companies and wider stakeholder the opportunity to engage with Ofgem via consultation will be crucial.

Ofgem's proposed 3% collar

The proposed 3% collar represents a significant asymmetric risk with significant downsides (potentially in excess of £13m per annum for SHE Transmission). This is an unreasonable liability; as we highlight throughout this response, and specifically in our response to the Impact Assessment, we see no evidence of Ofgem having calibrated the overall impact of asymmetric risks. We consider there to be strong justification for reducing the collar to 1.9% to reflect the shorter RIIO-2 period. In addition, the 3% collar appears even more unbalanced given the overall incentive package set out within Ofgem's Draft Determinations.

The proposed 3% collar also places extra emphasis on allowing for appropriate time to review the ENS Methodology Statement. Each TO will naturally wish to protect its position and ensure it is not penalised where a network issue is not as a direct result of its own action or failure. In addition, although not directly linked, Ofgem has proposed to significantly reduce our proposed asset replacement allowances. Unless this is reversed at Final Determinations, this will inevitably increase the overall network risk and the potential ENS performance. We do not believe this has been factored into Ofgem's decision to apply a continued 3% collar.

Timely Connections

We disagree with Ofgem's overall consultation position on Timely Connections retaining the incentive as per RIIO-T1, as we believe it misses an opportunity to improve the incentive to align it with customers' needs.

We have a 100% track record of issuing offers on time during RIIO-T1. As noted in our response to Ofgem's SSMD we believe the future incentive design should allow for flexibility if requested by customers. Our Commercial and Connections Policy outlines earlier engagement with the customer to ensure we arrive at the most optimal solution by the time we get to offer stage. However, if we are at the offer stage and a customer's request or circumstances have changed, and another option is requested then this should be a reasonable exception under the timely connections incentive. This flexibility would allow greater adaptable in delivering connections solutions, adaptability being key to deliver net-zero. This would be at a customer's request only.

ET Question 9: *Do you have any views on our overall approach to setting totex allowances?*

Our response is set out in the following sections to assist Ofgem and other interested stakeholders.

Section 1. Overview

Section 2. Cost assessment development process and common issues

Section 3. Load / Non-Load Related specific issues

Section 4. Non-operational capex

Section 5. Network Operating Costs

Section 6. Other

Section 1. Overview

Ofgem's overall approach to setting totex allowances needs to balance two essential outcomes:

1. Delivering efficient outcomes for customers
2. Enabling timely investment and output delivery by Networks

In its Draft Determinations, Ofgem's approach to setting totex allowances has cut our Plan by 33%; c. £800m. Careful review of the Draft Determination documents reveals there is no justification for reaching this outcome. Ofgem's approach therefore fails to achieve the balance required, will inhibit investment in the network and in so doing fail to deliver the outcomes that customers need.

Issues in each of the categories listed in the table below are present in the Draft Determinations leading to unjustified cuts in our totex allowances.

ET Q9 Table 1: Overview of our view on Ofgem's approach to settling totex allowances

AREA	ISSUE	REMEDY
Pre-construction (Load & Non Load related Capex)	Ofgem has cut funding for project development threatening the readiness of renewable generation investment to deliver 2030 targets. Ofgem's proposals to log up costs and recover in RIIO-T3 pose an unacceptable risk.	**£80m+ requirement:** reinstate core strategic project funding and approve revised baseline of £153m subject to end of period true-up. Approve an in-period reopener for projects that come forward during the period.
RPEs	£82m of RPEs is excluded from our baseline allowances despite commitment to include.	**Correct a £82m missing allowance error:** include £82m of RPEs missed from baseline allowances.
Overheads (Opex)	In calculating an overhead reduction based on a reduced capital programme Ofgem makes an error in deduction, which cuts more of the overhead than is associated with the reduced capital program.	**Correct a £70m modelling error:** reinstate our efficient costs deducted in error and reward our efficiency through the Business Plan Incentive.
Network Operating Costs (Opex)	By using historical data from before we built an HVDC network, Ofgem fails to account for the simple fact that we have both an AC and HVDC network to repair and maintain in our NOCs allowance.	**Correct a £45m disallowance**: using the data provided including justified tendered costs of £45m in allowances, maintaining critical infrastructure for northern renewables.
Risk (Load & Non Load related Capex)	Ofgem's method assumes outturn costs include risk, yet the vast majority of our costs are not based on outturn costs and so do not include risk. Ofgem fails to account for other elements of risk including volume risk.	**Correct a £57m methodological error**: revise assessment models to match published methodology and so doing reinstate risk costs of £57m of efficient benchmarked costs.
Frontier shift (Ongoing efficiency)	The extreme productivity challenge is not substantiated by the empirical evidence or, regulatory precedent, nor is it consistent with Ofgem's other draft decisions. The effect of this includes double counting of efficiency reductions.	**Remove unjustified £98m efficiency cut:** Ofgem's additional efficiency challenge of £98m which double counts the embedded £123m+ in our Business Plan and is fundamentally flawed.
Unit cost efficiency (Load & Non Load related Capex)	A combination of issues results in unit costs being unjustifiably cut, most notably Ofgem do not account for project specific factors and makes the wrong assumption that RIIO-T1 projects will be as per RIIO-T2 projects.	**Reinstate unjustified £86m cuts:** Ofgem fails to consider evidence provided for atypical project costs leading to cuts, particularly for underground cable.
Non-load project need cut (Load & Non Load related Capex, Non Operational Capex)	Ofgem sought more evidence and optioneering before it could support £323m of investment in replacement of aged renewable generation connection assets, network reliability, Critical National Infrastructure and smart technology. This has been provided and to retain its Draft Determination position would be an error based on both the original and enhanced evidence provided.	**Reinstate justified engineering need:** Ofgem must reintroduce investments where we have addressed its concerns. We have been able to accommodate some limited investment deferral to RIIO-T3. Ofgem should accept this revision and approve allowances and outputs totalling £284m.

Our views on the overall approach to setting totex allowances are covered across each of the main Business Plan Data Table (BPDT) totex groupings set out in the SHE Transmission Annex response questions. Our response on Real Price Effects and Ongoing Efficiency is contained in Section 2 of our Main response and our answer to Core Q10 and Core Q11. We also rely on the independent review of Ofgem's cost assessment process undertaken by Oxera[48] and referenced throughout this response.

Section 2. Cost assessment development process and common issues

a. RIIO-T2 cost assessment methodology - summary

There is no single cost assessment methodology document within the Draft Determinations. Within the ET Annex a selection of paragraphs (§3.20-3.29, §3.35-3.38, §3.41-3.43, §3.44-3.57) describe the general approach. The capex sections in particular do not contain any details of how Ofgem has ensured its models are designed to accommodate the challenges of assessing transmission expenditure and produce a balanced outcome. The general approach can be summarised as:

Capex – Load and Non-Load Related

- Asset costs – capping allowances at disaggregated level using its 'lower-of' principle. When applied this is the lower of: (i) RIIO-T1 6yr historical UC, (ii) RIIO-T2 Forecast UC or (iii) Company proposed UC.

- Non-asset costs were reviewed on a case-by-case basis.

- Risk and contingency (R&C) costs were based on the proposed company risk uplift with specific adjustments. These were: removal of R&C on asset costs based on methodology assumptions; removal of R&C for delivery phases out with RIIO-T2; applying R&C for remaining costs based on company submitted historical averages.

Capex - Non-operational

- Application of historical run-rates and trend analysis, comparison with Modern Equivalent Asset Valuation (MEAV) and Capex. Capital projects (property and IT) assessed on an individual basis.

Opex & Capex - Network Operating Costs

- Capping allowances based on the lower of historical UC or forecast UC applied to Company volumes.

- Capping allowances based on historical average annual costs or forecast average annual future costs, applied where Ofgem claims networks did not provide historical or forecast volumes.

- Capital or one-off projects were assessed on an individual basis.

Opex – Indirect costs

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[48] Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review, August 2020

- Econometric models for Business Support costs and Closely Associated Indirect costs (CAIs) across industries - Ofgem states both were top down, based on historical gross costs and tested for fit and plausibility of the relationship between drivers and costs.

- Interpreting the unpublished models, it is clear that Ofgem also tried to apply its capping principle (see above) to the model outcomes. We discuss particular issues with the actual approach in later sections, in our response to SHET Q10 and within an independent review undertaken by Oxera[49].

There is limited further cost assessment methodology contained within the individual company annex.

b. Development of cost assessment methodology and tools

As we noted in our previous consultation responses, we appreciate the challenge of developing a cost assessment framework for electricity transmission networks. However, Ofgem did not try to develop any outline modelling in advance of the Business Plan submission process nor share its proposals with the networks. This issue is also addressed in Oxera's report[50], section 3.2.

Communication of cost assessment modelling proposals: During the RIIO-T2 process no cost assessment model options were presented by Ofgem prior to the Business Plan submission. We believe the first time TOs were provided with any information on the structure of the cost assessment models or the modelling assumptions was within the sections of the published Draft Determinations, above, and in the subsequent weeks as Ofgem has released its modelling data to the networks. **Ofgem has missed the opportunity for feedback on how it might avoid many of the issues and errors we are now identifying within this response**

Timing / maturity of cost assessment data and information requirements: Although we support the requirements for provision of the supporting documents, the timeframes involved in setting out the new format required for the BPDTs and associated cost assessment tools has been challenging for all TOs and represents a significant change in reporting and tracking performance requirements. The maturity of the new BPDT reporting format and cost assessment tools therefore raises several concerns.

- The requirement for TOs to provide historical data that has not previously been collated or reported in the new BPDT format may have led to inconsistency in reporting of data between the three TOs. Our concern is Ofgem's methodology does not account for these potential inconsistencies nor has it attempted to subject the data to industry review ahead of the cost assessment process. **This raises concern over the robustness of the cost assessment tools particularly as Ofgem has not demonstrated how it has sought to reduce the scope for error. Our position is fully reserved as regards any issues that come to light following the submission of our response.**

- The requirement for TOs to retrospectively review this historical data without the benefits of industry working groups, without an accompanying modelling guidance document and

[49] Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review, August 2020

[50] Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review, August 2020

in less than 6 weeks (and in some instances less than 4 weeks) creates the potential that **TOs may have missed other issues and errors in the cost assessment modelling.**

- The maturity of the new guidelines and difficulties associated with applying principles and reporting definitions for transmission assets raises questions over whether the benchmarks derived can be considered to be free from the distortion of reporting noise. Ofgem's RIIO-T2 asset cost models are based on benchmarking unit costs for assets at a voltage category level. While this principle can work effectively where there are high asset volumes across repeatable and consistent projects, the application for transmission projects is untested.

  The potential for this to lead to outcomes which are not free from noise or error in this area is especially relevant when considering how costs will vary within asset categories due to factors such as power ratings, configurations, circuit lengths (long versus short), construction terrain etc. The potential for such differences which are not reflective of relative efficiency gaps should be cause for caution when using the results of derived metrics to set allowances. **Failure to do so can lead to incorrect and unjustified results.** We address this impact in section c below.

Applicable / comparable data sets: The available data set for some assets is limited. This can be due to low volume delivery in previous or forecast years. Ofgem has tried to adjust for this issue by using, where available, other benchmark data sets e.g. 33kV asset data from Electricity Distribution. Our concern is two-fold.

1. The comparison of limited data sets for transmissions asset against high volume distribution activities is flawed. The relatively small transmission data set cannot reliably be compared to high volume averages and will undoubtedly lead to assessment errors.

2. The use of other industry benchmarks is flawed as they will not reflect the challenges, issues and scale of delivering similar assets in a Transmission environment. This also introduces assessment errors.

Development of cost assessment models: The introduction of new, previously untested cost assessment tools based on untested input parameters has resulted in significant errors in Ofgem's assessment of our Business Plan. This outcome is the result of not testing potential models by subjecting them to industry and stakeholder review. Two examples include Ofgem's assessment of CAI and Risk & Contingency costs. Significant errors have occurred in both areas highlighting (i) a lack of consultation with the TOs to ensure consistency of input parameters; (ii) poor understanding of the practicality of the assessment tools for transmission business models; and (iii) no evidence the cost assessment outputs have been tested to verify the robustness of the assessment (i.e. logic test)

Failure to represent the transmission networks within model design: Ofgem's costs assessment process fails to take account of the information provided on the atypical costs for one off, non-standard elements. Furthermore, there is insufficient evidence that logic tests have been applied to the results of the cost assessment process. This has led to significant errors in the assessment of certain categories. For example, Ofgem's assessment for ongoing inspection and maintenance costs required for our Caithness Moray HVDC link failed even though we highlighted the cost increase throughout our plan and even though the need for the costs were identified by Ofgem's consultants when assessing the project need prior to approving construction.

c. Ofgem capping methodology

Ofgem's cost assessment process is based on setting benchmarks based on the lowest available metric and capping allowances at a disaggregated level. We highlight this in our general review of Ofgem's totex assessment as it impacts almost every assessment it undertakes and in total leads to a material distortion of the efficient costs which we, and other networks, should be allowed.

This primary issue arises because capping allowances at the lowest benchmark level available asymmetrically bakes errors and distortions which any cost assessment methodology is naturally subject to. In this case, adopting a lower-of approach across models bakes in all, and only, modelling distortions which set allowances below the real benchmark. This leads to a distorted outcome, setting totex allowances at artificially low levels.

Furthermore, its effect is further distorted when combined with the application of ongoing efficiency targets and the Business Plan Incentive (BPI) application which requires companies to be below benchmark to be rewarded – an outcome which the modelling methodology is designed not to permit.

Independent review: Our conclusions are supported in an independent review undertaken by Oxera in which it concludes the following.

'Given such challenges, a robust cost assessment framework for electricity transmission would need to carefully take into account the following factors.

- ***The comparability of different benchmarks****—including, but not limited to, the differences (e.g. in terms of outlook, activity mix) between RIIO-T1 and RIIO-T2; differences in regional factors affecting companies' efficient cost relative to other comparators; differences in regional factors affecting a specific project's efficient cost relative to internal or external benchmarks.*

- ***The potential for cost allocation/reporting inconsistencies or cost synergies*** *to affect the cost assessment framework and comparability of different benchmarks.*

- ***The scope for modelling error****—noting that unit cost analyses are models in the same way that econometric models are and can be highly susceptible to modelling error—and whether the regulatory framework leads to the impact of such error being biased either upwards (leading to higher totex allowances, to the detriment of consumer welfare) or downwards (leading to lower totex allowances, to the detriment of the ability of the company to finance its functions).*

In particular, Ofgem's cost assessment framework is not balanced as it removes the impact of potential positive modelling errors on companies' totex allowance by capping funding at the

Business Plan level, but retains the impact of negative modelling errors by applying the most stringent benchmark in several cases.'[51]

In its conclusions, Oxera also highlights areas of Ofgem's totex modelling which, it concludes, leads **to errors and unjustified reductions in our allowances for RIIO-T2**. These issues include the negative impact on totex incentives, the need for capping benchmarks, reliance on single reference points for benchmarking, failure to adjust for large variations in benchmark data, errors arising from double counting modelling cost adjustments, failure to account for variations caused by workload mix or scale and failure to account for explained atypical or regional differences.

The remainder of our response focuses on the specific errors and inconsistencies that have been identified across each of our Business Plan categories. These are also summarised in Table 1 above. Ofgem should correct the errors highlighted. Ofgem should also consider the suitability of its cost assessment process based on the errors highlighted and taking account of the recommendations summarised above and detailed in the Oxera report.

Section 3. Load and non-load related capex specific issues

Ofgem has applied totex cuts across our load and non-load capex program as per Table 2. We provide our detailed response to these proposed cuts in our response to the questions in the SHE Transmission Annex questions as referenced in the table. This evidence provides the justification for the reinstatement of these cuts in Ofgem's Final Determinations. The remainder of this section focuses on the cost assessment tools used by Ofgem for our load and non-load capex program.

ET Q9 Table 2 – Summary of Load and non-load related capex cuts

Draft Determination proposals	Value	Areas impacted	SHE Transmission Annex SQ Response
Project Engineering Need[52]	£80m £190.7m[53]	- Load Preconstruction - Non-load Schemes	SHET Q6 SHET Q7
Unit Costs[54]	£11m £75m	- Load - Non-load	SHETQ6 SHETQ7/8
Risks	£31m £25m	- Load - Non-load	SHETQ6 SHETQ7/8

<u>Engineering Project Need</u>

As outlined in Table 2 above, Ofgem has unjustifiably proposed a total cut of £270.7m across our Business Plan load and non-load related capex program based on its assessment of project need. We consider these cuts should be reversed in the Final Determinations following the correction of errors of fact and the review and acceptance of additional evidence provided with our consultation response. This is outlined below and in additional SHE Transmission Annex questions.

[51] Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review
[52] Net costs excluding indirects
[53] This doesn't reconcile to Ofgem's ref in SHET Annex, table 13 (work volume reduction £182.5m)
[54] Ofgem assessment of T2 expenditure only

Notwithstanding our concerns and challenge over the rejection of some needs cases, our view is that the needs case review undertaken by Ofgem has been, for most schemes submitted, robust and constructive. The EJP assessment framework used, considers a wide range of information (need, options assessment, efficiency of solutions, timings etc) and the corresponding feedback has been direct and productive during the assessment process.

We have highlighted our concerns over the rejection of the needs case for five load pre-construction schemes and ten non-load schemes. During the consultation phase we have worked closely with Ofgem and have committed to provide additional supporting information to support the justification for schemes that have been disallowed.

The additional information and enhanced justification we have provided for these schemes is detailed in our response to SHET Q6 and Q7.

We welcome Ofgem's consultative approach in this area and appreciate the opportunity to highlight existing supporting evidence that has been missed by Ofgem and where necessary have provided additional information to support our proposals.

Asset Unit Costs, Risk and Contingency

As outlined in Table 2 above, Ofgem has also unjustifiably proposed a total of cut of £86m across our Business Plan load and non-load related capex program based on its asset unit cost assessment of our Business Plan. An additional reduction of £56m is based on its assessment of our risk and contingency proposals.

We consider these cuts are the result of a combination of errors of fact and inconsistency between Ofgem's stated methodology and the models applied as summarised in the following three sections.

- **Unit Costs:** election of benchmark – average, upper quartile, minimum
- **Unit Costs:** adjustment for atypical costs and consistency between data sets
- **Risk and contingency:** application of historical efficient risk rates to future forecast cost areas

Capping of UC benchmarks at disaggregated asset category: Ofgem's approach for determining cost efficiency for asset costs is based on capping unit costs to the **lower-of**:

- Ofgem's benchmark – which itself is the **lower-of** the historical and forecast costs for each asset type across the three TOs (3.22); and
- the network company's proposed unit costs for the scheme (3.23).

As noted above, this approach makes no allowance for the variation and noise in the benchmark data and therefore adopts an unobtainable level of efficiency. This is confirmed by Oxera's observation '*In particular, Ofgem's cost assessment framework is not balanced as it removes the impact of potential positive modelling errors on companies' TOTEX allowance by capping funding* *at the Business Plan level, but retains the impact of negative modelling errors by applying the most stringent benchmark in several cases.[55]'*

This asymmetrical approach means that TOs will be penalised when costs are above the artificially low benchmark with no opportunity to benefit from additional allowances when costs are below Ofgem's benchmark. This approach is clearly wrong given the potential for high cost variances across asset categories based on the factors described above and doesn't reflect that in some instances, there will be good reason for asset costs being above the benchmark rates (e.g. atypical cost drivers such as non-standard equipment, higher ratings, low volumes etc).

Adjustment for atypical costs: Transmission projects are complex in nature and have many cost drivers which impact project expenditure. Examples of such drivers include building on brownfield versus greenfield sites, short versus longer circuit lengths, regional factors (urban versus rural challenges), nonstandard installations (e.g. low noise transformers), new build versus refurbishment. Considering these drivers is crucial in the identification, assessment and adjustment of atypical costs across our portfolio.

An example of this issue is seen in the variation of our underground cabling asset costs across several schemes in our Business Plan. The cost drivers for transmission cabling projects can vary drastically depending on several factors such as ratings, cable configurations, cabling lengths and installation terrain. To benchmark cabling investment the wide range of cost drivers in a relatively low data set across each of the TOs must be accounted for. There is no evidence that Ofgem has sought to adjust for these evidence variations.

Ofgem has therefore proposed allowance reductions totalling c. £67m associated with underground cabling assets across a variety of schemes in our Business Plan submission; when including those projects where the initial need was rejected, this rises to £82.2m. We have highlighted several factors that demonstrate why these costs must be adjusted prior to benchmarking these assets.

- **Data set:** A small data set has been used to set the benchmark unit cost based on T1 metrics (112km 132kV cabling & 28km 275kV cabling), therefore Ofgem cannot assume that the sample data is reflective of the subsequent T2 programme of works.

- **Project variations:** The average RIIO-T1 data set (12 Nr 132kV Data Points & 7 Nr 275kV Data Points) represents longer cable runs with only two data points for short run cables less than 1km; cabling works included for our T2 Business Plan schemes are heavily weighted towards smaller, short runs, therefore Ofgem cannot assume the costs for our T2 scheme will be comparable to their benchmark

- **Regional / location:** The average RIIO-T1 data set (12 Nr 132kV Data Points & 7 Nr 275kV Data Points) represents work in agricultural land, the mix of cabling works included for our T2 Business Plan is heavily weighted towards work within existing brownfield site substations (60%), therefore Ofgem cannot assume the unit costs between T1 & T2 will be comparable.

[55] Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review

- **Variation within projects:** The use of a simple average length per project also fails to capture the variation in the average cable run length within each project, therefore Ofgem is not considering a sufficient level of project granularity to make an accurate assessment.

Our responses to SHET Q6 and Q7 develop these points further.

Forecasting risk and contingency: Ofgem sets out within the Draft Determinations its approach which is based on removing '*risk and contingency components associated with assets where our applied benchmark unit costs were set by historical levels, because it already includes the relevant outturn risk*'[56]. This is a clear error since in the assessment Ofgem has not based its proposed RIIO-T2 allowances on outturn unit costs, with 73% of the proposed cost allowances being derived from forward looking RIIO-T2 unit cost benchmarks of the company proposed expenditure.

Furthermore, Ofgem highlight its approach is based on removing risk and contingency associated with delivery and construction phases of projects sitting outside RIIO-T2. This approach needs to be proportionate based on the level of expenditure out with the RIIO-T2 period. Please see our response to SHET Q6 and Q7 where we set out our detailed response for rejection of Ofgem's proposed cuts for risk and contingency and for our detailed response to Ofgem's proposal for projects spanning price controls.

Section 4. Non-operational capex

We have summarised the cuts proposed by Ofgem across our Non Op Capex program in Table 3 below:

ET Q9 Table 3 - Summary of Non Operational Capex cuts

Draft Determination proposals	Value	Areas impacted	SHE Transmission Annex SQ Response
Unidentified	£5.1m	IT Projects	SHET Q8
Project Need	£52.5m	Warehousing & Transmission Control Centre	SHET Q8

The cuts proposed within this category relate to rejection of two schemes (Warehousing and a new Transmission Control Centre) based on justification of need, along with a generic cost reduction on IT, despite Ofgem's own consultants, Atkins, stating our plan is supported by a sound, verifiable bottom-up cost estimation facility. We have presented additional supporting information within this response in SHET Q8. This includes review by expert consultants, updated cost benefit analysis and revised Engineering Justification Packs. We believe these totex cuts are unjustified and should be re-instated in the Final Determinations.

[56] RIIO-2 Draft Determinations - Electricity Transmission Annex

Section 5. Network Operating Costs

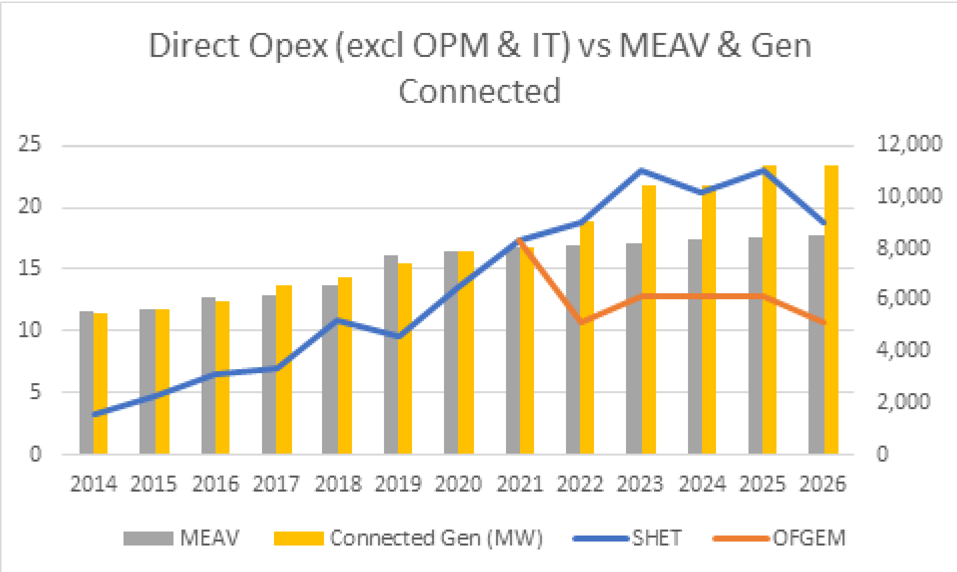
ET Q9 Table 4 - Summary of Network Operating Cost cuts

Draft Determination proposals	Value	Areas impacted	SHE Transmission Annex SQ Response
Project Need	£72.4m	Transmission Communications Upgrade & Integrated Condition & Performance Monitoring	SHET Q9
Unit Costs	£45.1m	Faults, inspections, Repairs & Maintenance, Vegetation management	SHET Q9

The cuts based on need justification relate to rejection of two schemes (Transmission Communications Upgrade & Integrated Condition & Performance Monitoring). We have presented additional supporting information for inclusion of both schemes and these cuts should be re-instated in the Final Determination in line with our response to SHET Q9.

We strongly disagree with the unit cut proposals, as outlined in our response to SHET Q9, which sets out errors in the cost assessment process. The following graph clearly highlights the illogical nature of Ofgem's totex proposals in an activity area where the size and scale of a network is clearly going to drive costs. The following bullets summarise the cause of this unjustified outcome.

Figure 5 – RIIO-T1 vs. RIIO-T2 Network Operating Costs (Business Plan and Draft Determinations)



- **Tendered HVDC costs:** Failure of Ofgem's cost assessment process to take account of the atypical costs associated with the service and maintenance costs for the Caithness moray HVDC link.

- **Inappropriate use of unrepresentative annual average costs:** Ofgem's cost assessment benchmark introduces a bias towards the first 6 years of RIIO-T1 not reflecting the scale and complexity of our network in the RIIO-T2 period.

- **Failure to use volume information provided:** Ofgem's failure to consider additional information provided in SQ70 as part of its assessment. This has amplified the issues created by using unrepresentative historical annual average costs in place of volume forecasts.

These cuts should be reinstated in Ofgem's Final Determinations.

Section 6. Indirect Opex – Business Support Costs & CAI

ET Q9 Table 5

Draft Determination proposals	Value	Areas impacted	SHE Transmission Annex SQ Response
Unit Costs (1,2 &4)	£94.6m	Business Support Costs (BSC) & Closely Associated Indirects (CAI)	SHET Q10

Most (£93.9m) cuts relate to CAI costs, which is addressed in detail in section 2 of our main response and within SHET Q10. Further analysis has been undertaken by our independent consultants, Oxera. We rely on that report in full and do not seek to replicate it here. Its report and conclusions are provided with this response.

We believe Ofgem's CAI model contains a fundamental error. It deducts both a workload adjustment and capping (outperformance) adjustment in error where only one is justified.

- Capping involves limiting allowances to the lower of Ofgem's benchmark or the company submitted forecast. Issues this this method are developed further by Oxera in its report[57]. In CAI, Ofgem has calculated the difference between its modelled costs (£297m) and our Business Plan submission (£245m)[58] as £58m. Its capping adjustment.

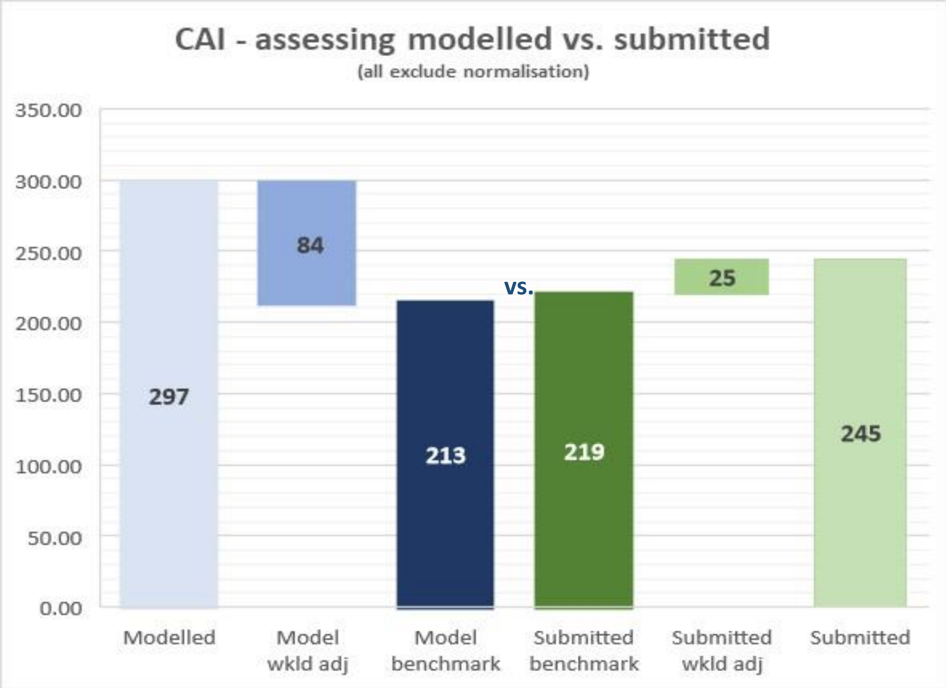
- Ofgem has also reduced our capex allowances following its engineering need review. Using its econometric model, it estimated the value of this workload reduction, £84m. We also identified the CAI forecasts associated with the rejected engineering need, £25m.

We believe that Ofgem intended to adjust both the modelled and submitted CAI costs for the revised workload level and compare the workload adjusted CAI benchmark to company submitted equivalent. This is represented by the following graphic and results in the comparison of £213m and £219m.

[57] Oxera (September 2020), Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review.

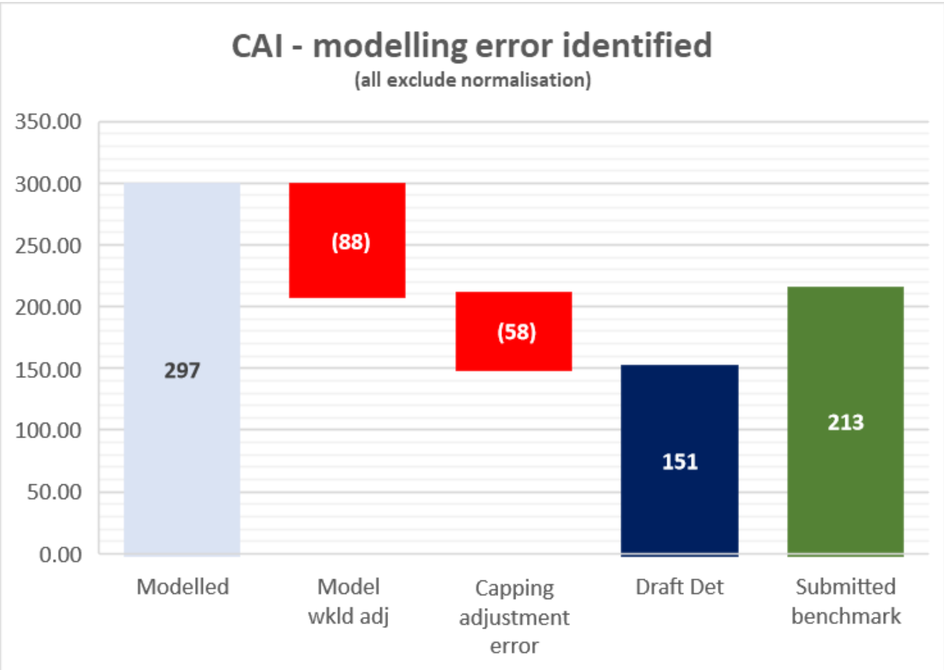
[58] Both these CAI numbers are after separately assessed costs are removed, i.e. they are normalised costs.

ET Q9 Figure 6 – comparing modelled and submitted workload adjusted CAI



However, Ofgem's modelling is flawed as it applies both a capping adjustment and workload adjustment resulting in a double count error. The error is created because Ofgem deducts the capping adjustment from the already efficient modelled and workload adjusted CAI costs. This is represented in the following graphic.

ET Q9 Figure 7 – Ofgem modelled CAI showing 'double count' error



Initial discussions with Ofgem indicate there is a sequencing error in its model which we have been advised will be corrected. This leads to a double count error of c.£60-70m. Correcting for this should lead to the reversal of this deduction.

At a total CAI level our submitted costs represent materially better value for customers than the efficient costs produced by Ofgem's own economic modelling. Our Business Plan CAI forecasts also represent a comprehensive bottom up assessment of overheads required during RIIO-T2 and detailed breakdowns of the allocation of CAI overheads to capital projects. Given the model design points noted below, we believe that our Business Plan workload adjusted CAI costs should be accepted as efficient and more reliable than Ofgem's modelled outputs.

Therefore, our submitted capitalised overheads in relation to capital projects that have been cut for volume is only £25m. Ofgem should only deducted this portion from our Totex forecast, subject to any changes in the level Ofgem's engineering need assessment at Final Determinations.

Accounting for new and specific stakeholder requested expenditure

In addition to the above, the modelling performed by Ofgem does not cater for specific items included within our plan such as:

- Operation of the HVDC multi terminal test environment, which during RIIO-T1 was funded under NIC. The cost of this is now with baseline opex as previously advised by Ofgem and this is included within our RIIO-T2 plan at c.£0.8m per year split between BSC and CAIs.

- Also included within our plan are new policy items which Ofgem has approved such as stakeholder engagement, sustainability and our environmental action plan (to name a few) and with this proposed cut we will not be able to deliver these.

- Additional operational training costs are also included due to our aging workforce and the need to bring in new recruits to replace them. Again, the modelling does not deal with this.

- These proposed cuts also impact our ability to implement certain policies which Ofgem has already approved, one of which is the Network Access Policy (NAP). The first and most important principle in the NAP (Special License Condition 2J) is maintaining a safe and reliable network. This is required to protect anyone in proximity to our assets and to ensure supply reliability. If our ability to maintain a safe and reliable network is compromised, then we are at risk of not being able to meet these license obligations. In all cases across GB, SHE Transmission has the best annual system availability, winter peak system availability along with the least loss of supply incidents (see NGESO published system performance reports). A lower resource as a result of incorrectly reduced allowances could create this operational tension.

Furthermore, as outlined in our Business Plan our CAI expenditure has already been benchmarked and found to be efficient by both CEER (Council of European Energy Regulators) and our own consultants Oxera. Both these reports should have led to Ofgem checking the illogical nature of its Draft Determination conclusion, i.e. that the most efficiency network, SHE Transmission, incurs a 37% cut in allowances.

General comment on econometric modelling

In Ofgem's independent consultant's report, our BSC and CAI costs are consistently identified as representing the industry efficient level. We note the range of models developed and tested. While we accept there is no perfect model, we believe Ofgem could identify a better balance of explanatory variables in place of those currently proposed.

We agree that capex and MEAV (the size of our network) are both appropriate cost drivers for CAI overheads. However, the model identified does not appear to pass the logic test as the coefficient weightings used favour capex over MEAV whereas only a proportion of our CAI costs are driven by capital projects.

MEAV (Modern Equivalent Asset Value)

Ofgem has decided to use MEAV as one of its cost drivers for the CAI modelling, however there was no guidance provided by Ofgem as to how this is to be calculated and each TO came up with their own methodology, which also raises concern around the potential inconsistency of data.

Final Determinations

We look forward to seeing revised models ahead of Final Determination which correct for these identified errors and issues and being provided the opportunity to review these.

For additional details of items included within our plan, the following document was submitted with our Business Plan "T2BP-EJP-0014 Operational Expenditure Justification Paper".

Section 7. Other costs

ET Q9 Table 6

Other Costs	Value*	Areas impacted
Not assessed	£6.2m	Physical Site Security
Not assessed	£31.8m	Injurious Affection
Not assessed	£5.8m	Cyber security

Ofgem has still to assess the Physical Site Security (baseline) and Injurious Affection costs which SHE Transmission had originally submitted as an uncertainty mechanism. We welcome Ofgem's view to move the Injurious Affection into baseline Totex, however we still believe an uncertainty mechanism should exist in this area. We await Ofgem's communication so an informed view can be taken before Final Determinations.

Information regarding Cyber Security is not being published in the public domain, as such we have no comments to make at this stage.

***ET Question 10**: Do you agree with our proposed eligibility criteria for the LOTI re- opener and do you agree with the assessment stages, and their associated timings?*

Whilst we support the purpose of the LOTI mechanism and associated eligibility criteria, we do not agree with the assessment stages and their associated timings.

We have previously provided detailed feedback to this effect in our emails of the 1 April, 5 May and 13 May 2020, a summary of which is provided below.

Scope, eligibility, timing and accessibility: We support Ofgem's minimum materiality threshold of £100m and that the re-opener will be available to TOs at all times throughout the RIIO-2 price control. And we welcome Ofgem's clarification that projects eligible for funding under LOTI will include those which are non-load related, as well as strategic wider works and generation and demand connections.

Approval process: We remain concerned that the LOTI assessment stages and associated timings seem to be based on timescales for typical NOA driven strategic wider works and have not been reassessed to reflect the changing scope of the LOTI mechanism from SWW and the full range of eligible projects that it will apply to and the associated timescales for these (e.g. connection driven projects, CfD auctions). Ofgem's proposal to introduce consecutive lengthy assessment timescales risks creating **delay to timely infrastructure delivery needed to address system risk, constraint costs for consumers, customer driven needs and of course, net zero.**

To make LOTI fit for purpose Ofgem must take an agile approach to intervention to ensure the regulatory process doesn't act as a barrier to achieving net zero targets. LOTI must allow for a bespoke/tailored assessment of project need and costs, whilst still managing project delivery in a timely manner to avoid unnecessary delays to required network investments.

1. **There should be flexibility in the assessment timetable to meet the needs of the specific project.**

On this basis, we disagree that Ofgem should be more prescriptive regarding the assessment stages or that this level of prescription is required in the licence. This could result in unnecessary restrictions on both the TO and Ofgem to assess projects within suitable timescales during RIIO-2. We think it will be necessary for Ofgem to remove this prescription from the licence and include further detail on the approvals process within the associated LOTI guidance, which we understand will be consulted on and in place for the start of RIIO-T2, giving all affected stakeholders opportunity to comment on the process as a whole. Including this detail in the guidance rather than the licence also affords Ofgem the opportunity to make changes throughout the RIIO-T2 period where necessary. We note that there were two iterations of the SWW guidance during RIIO-T1 so the need for flexibility in the approvals process is not unfounded.

2. **A two-stage Needs Case process should only be followed where needed and where permitted in the programme for the project**

We note that Ofgem indicates the FNC review and approval will be completed within a 3-6 month timeframe but that Ofgem will not be bound to these timescales (this has also not been our experience under RIIO-T1). We also note that the proposed 3-6 month approval period for a FNC is only after a 12-month review of an Initial Needs Case (INC), resulting in a minimum 16-18 month

Needs Case review before approval, followed by commencement of the project assessment (PA), which will then take another 9-12 months.

We welcome Ofgem's recognition that the timescales outlined in its proposal may not be practical for specific projects and that alternative timings can be sought by the TO in these instances. However, we disagree with Ofgem's suggestion that this should only be by exception and under exceptional circumstances, which are expected to be rare. We also believe flexibility in the assessment stages should go further to allow TOs to seek a one stage Needs Case process where necessary (i.e. straight to FNC) in both circumstances where there is a strong, evidence-based need or where project programme requirements are short, with Ofgem committing to a decision on the FNC within six months of receipt.

3. **Ofgem should be flexible in its approach to accepting the FNC and should commit to reach a decision within 6 months of receipt of a full submission**

We disagree that a TO must have "secured all material planning consents" before submitting its FNC, this is not aligned with Ofgem's approach under SWW in RIIO-T1 and risks creating undue delay to the regulatory approvals process and as such to project delivery. We have previously recommended that the FNC should instead be accepted by Ofgem at the point where the TO has sufficient certainty over the project design. For example, the completion of pre-application consultations, wayleaves discussions and, if necessary, Environmental Impact Assessment (EIA) should provide suitable comfort that project is unlikely to significantly change, therefore further delay to the submission of the FNC is not warranted. In addition to this, for most large projects, the consenting approval process will form the critical path for the preconstruction programme. This means that for many projects, achieving consents will normally coincide with the project being ready for construction beginning (please also see our response to ET Q11 for further commentary on the importance of pre-construction funding for LOTI projects). Accepting the FNC at this earlier stage is in line with the approach taken with SWW FNCs submitted in RIIO-T1 and Ofgem has provided no evidence to demonstrate that this has not been appropriate or has created problems with providing FNC approval. Planning consents can also be time limited so to delay the FNC approval process could be detrimental to the delivery of the project.

4. **A Project Assessment decision should be made within six months of receipt of the PA submission and should proceed the start of project construction**

It is important that not only FNC approval but also Project Assessment (PA) approval are granted by Ofgem ahead of project construction. This fully incentivises the TO to strive for cost efficiencies under the TIM. Ofgem should commit to providing a PA decision within 6 months of receipt of a full submission and before the TO is required to commence project construction.

We disagree with Ofgem's proposal that the PA must only commence following FNC approval. Our experience demonstrates that through the procurement/tender award timelines, best and final offers [BAFO] are received from contractors in advance of PA and can be assessed in parallel with the FNC. Further, there are non-contractual elements of PA that can be assessed prior to BAFO such as project management costs, allocation of risk and contingency. Commencing the project assessment, where necessary, in parallel with the FNC assessment will ensure timely review of efficiently incurred costs and determination of allowed revenue ahead of project delivery. This is important given the scale of investment required for these large capital projects and associated cash flow and financing implications which would result from funding such capital expenditure in advance of any revenue being received. We experienced this during RIIO-T1 with our Caithness-Moray SWW and agreed a ‘work-around’ with Ofgem to address the delay to allowed revenue for the project as a result of the PA decision not being implemented in time for project delivery. And most recently we have had to propose a similar work-around for our Shetland and SWW which faces similar issues due to the delayed PA and decision on allowed revenues. An earlier FNC approval and PA process would negate the need for such work-arounds during RIIO-T2.

Consequences: There are three main consequences of Ofgem’s LOTI proposals:

Project delay: The Needs Case approval process and associated timescales will result in delay to the commencement of project delivery and subsequent delay to timely infrastructure delivery needed to address system risk, constraint costs for consumers, customer driven needs and of course, net zero.

Cashflow impact: LOTI schemes will require SHET to spend before approval of allowances as a result of the timing and timescales for the PA. This increases both risk and cashflow impact. Yet, this is not considered by Ofgem in its impact assessment or financeability testing (as noted we will provide this is our review of the Impact Assessment which we will provide by end of September).

Net zero impact: The LOTI mechanism, alongside MSIP (see ETQ13) and preconstruction (see ETQ11), must be applied to a credible net zero investment scenario to demonstrate effectiveness. This has not been done and we believe it will hinder Net Zero ambitions. We set out detail on this in our response to Core Q20 and Core Q21.

***ET Question 11**: Do you agree with our proposed definition of PCF for RIIO-2, and the areas of work that we intend that definition to cover?*

We strongly disagree with Ofgem's proposed definition of PCF for RIIO-2, and the areas of work that the definition covers. If this definition is retained, it will act as a barrier to the achievement of net zero targets and disenfranchise stakeholders by going against the current (and successful) collaborative engagement in the development of capital investment options.

Ofgem's proposal is based on providing "pre-consenting funding" and not "pre-construction funding", i.e. Ofgem funds to submitting planning consent and not to construction. This leads to a gap in regulatory framework. There is no route for cost recovery for those projects that ultimately do not proceed. We could recover the funding between submission of planning consent and construction where projects proceed but where they don't there is no means of cost recovery. Ofgem is proposing that the TOs carry that risk yet TOs are not the party who controls whether a project proceeds or not; therefore it is not legitimate to place that risk on TOs.

We propose the following definition of PCF:

'The necessary funding to undertake the required activities to take a given project to a point where it has obtained the necessary consents to permit it's construction <u>and</u> has achieved a suitable level of design to enable construction to commence following receipt of consents'

This is in line with the RIIO-T1 definition and will avoid significant adverse consequences and achieve positive outcomes as follows:

- Pre-construction activity is essential to enable us to **meet customer connection dates**, deliver increased strategic network capacity so **avoiding constraint costs** and **reduce reliability risks**, and to achieve these aims at the right time and efficiently. The pre-construction process is critical for the successful delivery of the increasing renewables driven investment in the network by ensuring we are ready to connect and transport new generation at the right time and in the right location.

- Proportionately low investment incurred at this stage allows us to **optimise costs** during the high cost construction stage, as well as ensuring new transmission infrastructure is delivered in the most efficient timescales to meet customer requirements. It is through rigorous and thorough pre-construction activities that **innovative** and **whole system solutions** are identified, risks for the construction phase are mitigated and all stakeholders can participate in co-creation of the optimal system development pathway.

Given the critical importance of pre-construction as an enabler to net zero outcomes, we are unclear as to why Ofgem is proposing barriers to timely investment, both through its proposed definition and retrospective funding approach. We note with concern Ofgem's proposal under 'Increasing Competition' (Chapter 9, Core Document) that TOs "do not carry out any development work on eligible UM projects that is detrimental to the application of late competition". We would welcome assurance from Ofgem that its approach to pre-construction is not being influenced by its nascent proposals for late competition. Not only does this proposal lack any detail to allow us to assess the effect in practice, it has the potential to affect the TOs ability to optimise costs, ensure efficient delivery and lead to delays to project delivery. This is not in consumers interests and creates outcomes contrary to what Ofgem seek to deliver through competition – i.e. increased costs.

The potential growth on our network over the next decade and beyond is significant as highlighted in the figure below. Pre-construction funding is essential so that we not only deliver on the potential but do so optimally:

The latest dataset for the ESO's Future Energy Scenario (FES) 2020 predicts a potential growth in renewable generation of up to 14GW additional generation connecting onto our network over the next decade (greater x3 growth compared to the past decade). Our own analysis demonstrates that this is a highly credible outcome, as sufficient generation is well developed to connect before 2026 and there is a pipeline of generation out to 2030 under development. This new generation is made up of a mix of schemes that are already in progress (3GW from our Certain View), generation ready to bid to secure funding through future CFD auction rounds (1-2.5GW), future Scotwind leasing schemes (up to 10GW) and future Scottish Island connections (1.5GW+). In addition, we expect significant local growth associated with new demand through initiatives such as rail electrification and electric vehicle charging. To enable this growth and the associated additional infrastructure, it is critical that SHE Transmission is adequately funded to develop new schemes in the most efficient manner and, most importantly, to meet required delivery timeframes both within the RIIO-T2 period and beyond.

We have a track record of successful large project delivery. Investment in pre-construction, not pre-consenting, form the foundation of this success

Throughout the RIIO-T1 period SHE Transmission has demonstrated sector leading performance in the development and delivery of large transmission schemes across our network. This has included the use of innovative new technologies (e.g. HVDC, subsea, new conductor and pole technologies), as well as quick response times to changing customers' needs (for example, the transition from the RO to the CfD).

A key factor in our success has been the approach taken during the pre-construction phase, working with customers, stakeholders and the supply chain, to optimise overall project timescales and ensure efficient construction costs through robust tendering and pre-construction design activities. As discussed in our meeting with Ofgem, 27/8/20, we set out our key pre-construction activities for a typical project using two scenarios:

PCF covering all activities required to commence construction (SHE Transmission current model and proposed definition); and

PCF that excludes non-consenting activities (Ofgem's proposed definition)

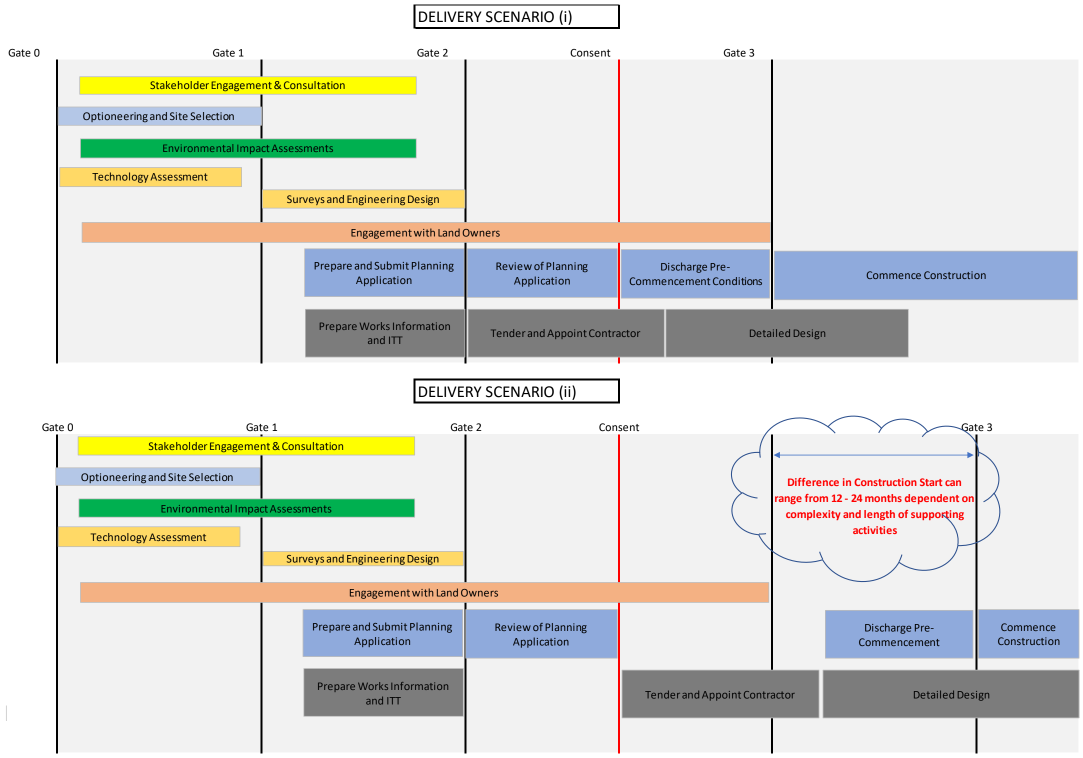
Both delivery scenarios are presented against our Large Capital Projects governance gate process:

- Gate 0-1: Opportunity Assessment
- Gate 1-2: Development
- Gate 2-3: Refinement

PCF Activities:

Inputs	Deliverable	Required For
System Parameters and Analysis	System Studies	Determining technology requirements e.g. requirements for reactive compensation and indicating the preferred area in which infrastructure is to be located
Desktop Studies, Constraint Analysis, Stakeholder Consultation, Engineering and Environmental Studies	Route/Site Selection Report	Informing the Preferred Option to be taken forward to achieve Consents for and to ultimately construct
Desktop Surveys, Constraint Analysis, Site Walkovers, Engineering Design and Studies	Preferred Route Alignment, Tower Details and Conductor Selection	Informing the Environmental Assessment, submission with the Planning Application and informing the construction works
Desktop Surveys, Constraint Analysis, Site Walkovers, Engineering Design and Studies	Substation Layout, Building Dimensions	Informing the Environmental Assessment, submission with the Planning Application and informing the construction works
Noise Assessments, Landscape and Visual Impact Assessments, Protected Species Surveys (Ornithology, Terrestrial etc), Cultural Heritage Assessment, Peat Slide, Biodiversity Net Gain, Forestry, PWS	Environmental Impact Assessment Report	Informing the final design, submission with the Planning Application and to inform the construction works
Feedback from Stakeholders	Consultation and Stakeholder Outputs	Informing the overall Design and Construction, required for the Planning Application
Landowner Negotiations, Legal Documentation	Heads of Terms	Provision of consent (Section 37 Applications) and to allow construction works to commence
Surveys, Equipment Dimensions and Performance Data, Modelling Outputs	Engineering Studies – Earthworks Calculations, Drainage Designs, Flood Risk Assessments, Transport Assessments, Earthing Studies, Building and Foundation Design, Primary and Secondary Plant Design	Informing the Final Route/Layout to be submitted as part of the Planning Application and its assessment, informing the construction works and the undertaking of them
Outputs from the Environmental Assessment, Engineering Studies, Stakeholder Engagement Outputs	Detailed Drawings	Informing the Planning Application Package, Land Agreements and the Works Information
Route/Site Selection Report, Environmental Assessment, Engineering Drawings (e.g. Building Heights, Layouts, Access, drainage), Consultation Outputs, Land Agreements	Planning Application Package	Gaining the Consent required to permit Construction
Environmental Assessment, Land Agreements, Engineering Drawings, Studies and Designs, Specifications	Works Information and Design Deliverables	Gaining the required appointment of a Contractor to undertake the required design work to discharge Pre-Commencement Conditions and undertake Construction

Delivery Scenarios (i) & (ii)



Our current delivery model is based on a compressed program of works across all phases of the pre-construction process as shown in scenario 1 above. A key element for this approach is the appointment of a contractor after Gate 2 thus allowing early progression of detailed design works with a view to discharging all pre-commencement condition in advance of construction commencing. This approach provides the following benefits:

Allows the rigorous selection of the most appropriate option for construction;

Allows for optimum programme delivery through achieving readiness for construction following receipt of consents;

Allows for efficiencies to be included at the point of submission of the Consent Application to deliver value for the consumer; and

Provides for a firm price for delivery of the project at the end of the Pre-Construction Phase

As highlighted in Scenario 2 above, the impact of limiting PCF to activities associated with achieving consents turns a concurrent approach into a sequential approach. This will increase costs, reduce the opportunity for innovation and collaboration, and ultimately has the potential to add significant additional time onto overall project timeframes, potentially resulting in 12-24 month delays.

In our ongoing discussions, Ofgem has suggested that TO's should continue to proceed based on the Scenario 1 program and recover additional costs associated with non-consenting issues as part of overall project construction allowances. It is not clear why this would be preferable to the alternative of modifying the definition to align with successful working practice.

In addition, we would strongly disagree with this approach for the following reasons:

- The cost associated with these unfunded activities will be substantial. We have undertaken an initial review of the five schemes proposed within our baseline PCF and estimate SHE Transmission would be required to commit more than £40m to maintain required timeframes in line with the scenario 1 programme across all of these schemes;

- The regulatory funding gap Ofgem is proposing means that SHE Transmission will be required to carry an unreasonable level of risk if we progress all PCF activities required to meet delivery timescales. This is not a reasonable risk to ask SHE Transmission to carry. We cannot carry that risk as we ultimately do not control if a project proceeds or not. For instance, we do not control the outcome of CfD and we do not control the outcome of the regulatory process which puts in place conditions that add risk to whether or not projects proceed (e.g. conditional of generators being successful in securing CfD).

- The timescales before these additional costs can be recovered will be substantial – likely to be more than 2/3 years, meaning it could be up to 5 years before TOs receive revenue for these costs;

- Ofgem's proposed approach will alter TO behaviour, either:

    - TO's take a risk averse approach and delay spend until all required funding is in place – resulting in significant delays to project timeframes and increased costs later in the project due to loss of efficiency; or

    - TO's approach is based on reduced design and preparation works – resulting in poor project definition and scope design leading to significant increase in construction contract costs, and likely project delays.

Ofgem's proposed approach introduces a regulatory funding gap which is not in the interests of the consumer and will present a significant barrier in delivering our net zero ambitions, and ultimately will result in significant additional construction costs.

Ofgem has two options to close its proposed regulatory funding gap:

1. **Approve needs case with no conditions before planning approval and ensure that pre-construction activities that take place post consent are included in the construction process; or**

2. **Approve our proposal for pre-construction allowances which includes our definition of pre-construction (not "pre-consenting funding"). This has the protection for consumers that PCDs must be delivered or the funding is returned to consumers.**

Failure to address this funding gap, based on our experiences from the RIIO-T1 period, will lead to delays in projects, inefficient process and ultimately poor stakeholder engagement, which is contrary to a key component of the RIIO-2 framework. Our experience of managing stakeholder expectations (customers and wider political) in the development of the Scottish Island schemes during RIIO-T1 highlights the impossible position SHE Transmission could face in developing schemes with complex drivers and risks that are far beyond our control.

Price Control Deliverables (PCD) for PCF

Ofgem's has also indicated that PCF allowances will be attached to a Price Control Deliverable (PCD). We support the proposal for PCDs associated with PCF and present our views on suitable outputs for consideration in the table below. Our support of PCDs add further weight to supporting baseline pre-construction funding. If we can't justify not delivering the PCDs, the baseline allowances will be returned to consumers:

Stage	PCD output
Opportunity Assessment	**Detailed Optioneering Report** outlining the proposed option (in some cases there may be a strong case to take forward multiple options) to the Development phase. The works typically required to complete this phase will include: • high level options appraisal • CBA analysis • preliminary engineering design evaluations • high level environmental appraisal for options under consideration & initial stakeholder engagement.
Development	**Consent Application**. Our proposal is based on assigning a PCD for consent application (single PCD covering all elements: overhead lines, substations, underground cables, subsea cables). The activities required in advance of submitting a Consent Application will typically involve: • detailed route and site optioneering studies involving all technical specialists (engineering, environmental, cost), • extensive stakeholder engagement and consultations, • detailed route & site design including detailed engineering design, subsea surveys where applicable and environmental impact assessments, wayleave & planning application costs. **Tender package.** Development of a tender package for the main construction activities including: • Works information – design specifications, programme, consenting details, CDM info, Env & consenting information etc • Site Information – Site Investigation surveys, feasibility studies, utility drawings, existing asset surveys/information etc
Refinement	**Consent Approval**. Ongoing stakeholder management to ensure consent applications area approved during the refinement phase. Associated activities could include defending proposals in a Public Inquiry. **Construction Ready**. Our proposal is this PCD is based on the project being ready for construction including all the following activities: • detailed designs complete, • condition discharging, • additional Site Investigation complete where required and justified, • all tendering activities project costing scope and schedule completed and approved.

***ET Question 12**: Do you agree with our proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out in Chapter 4?*

We strongly disagree with Ofgem's proposal to assess PCF costs as part of RIIO-2 Closeout, following the principles set out six years previously in the RIIO-2 settlement. This approach, if retained, is a barrier to the timely delivery of the critical system investments required for achieving pathways to national net zero targets both within the RIIO-T2 period and beyond to 2030.

We understand Ofgem's proposal to assess PCF costs as part of RIIO-2 Closeout to be designed to apply to apply to future uncertain schemes that are not included within our baseline funding. Based on the narrative set out in Chapter 4, we highlight the following concerns along with our proposal for recovery of costs:

1. **An ex post cost assessment as part of RIIO-2 Closeout for future uncertain schemes will require TO's to spend significant amounts at risk**

Although we acknowledge Ofgem's recognition of the importance of TO's progressing future uncertain schemes in a timely manner, we do not agree that the most appropriate way to fund this important activity is retrospectively. The level of expenditure that could be required for PCF activities on future uncertain schemes not included within baseline funding is significant. This means, under Ofgem's proposal where TO's PCF costs will be assessed through an ex post cost assessment as part of RIIO-T2 Closeout, TOs will be exposed to significant costs on preconstruction activities with no assurance on the level of allowance that will be approved.

Given the potential scale and complexity associated with the development of large transmission infrastructure schemes, it's unreasonable for TOs to be exposed to these additional costs without mechanisms in place to provide certainty on allowance recovery levels. The scale of expenditure anticipated for the five baseline schemes proposed in our latest submission to Ofgem totals £124.5m (Pre-construction funding Paper – T2BP-PAP-0016, this highlights the significant scale of PCF required to undertake thorough efficient and timely development of each scheme in advance of the construction phase). The implications of waiting to the end of the RIIO-2 period before additional allowances are agreed and applied are that TOs will face a delay of up to 7 years before they are able to recover revenue for these schemes. This is unacceptable.

The issue of concern is not that PCF will be required – all parties agree that is certain. The issue is for what investments, at what time and how much. Given this, we argue that within the period there should be there should be an appropriate regulatory uncertainty mechanism.

Our proposal is that additional PCF funding can be triggered through an annual re-opener for:

(i) new LOTI schemes identified either through the annual Network Options Assessment (NOA) process and/or schemes driven by new generation contracts; and

(ii) significant changes in scope associated for schemes in the baseline allowance (e.g. requirement for public inquiry, or significant changes in background generation resulting in alternative scope).

Our proposed reopener:

- would be annual - 1 month after the annual NOA publication (e.g. by 1st March each year) and will approve allowances for inclusion in the Annual Iteration Process (AIP) in that year; and
- would not be subject to a materiality threshold.

It's important to recognise that our proposal is based on all PCF expenditure for large strategic expenditure being subject to an end of period symmetrical true-up, based on an ex-post efficiency review of actual costs. The important point here is that it's critical TOs have adequate funding in place to progress the development of new large infrastructure in a timely and efficient manner to facilitate net zero targets. TOs should not be incentivised for this work and therefore this expenditure should not be subject to the Totex Incentive Mechanism.

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2. Trigger for PCF for future uncertain schemes

We described the scope of works for an annual re-opener mechanism above.

Ofgem has acknowledged that the NOA 'Proceed' signal provides a trigger on the need to incur PCF for schemes that provide wider system capacity across transmission boundaries and has invited suggestion on suitable triggers for PCF for schemes not covered within NOA. Given the nature of our network and our experience of developing large strategic schemes in the RIIO-T1 period, consideration of PCF for large strategic schemes not covered within the NOA process is critical for the RIIO-T2 period. Typical examples of schemes include the development of long radial links to our remote islands and complex shared use infrastructure schemes to support renewable generation across our local regions. Our proposal for the trigger for PCF covering schemes not included in the NOA process is two-fold:

(i) A signed connection agreement in place for at least one customer (licence obligation to connect) which triggers the need for the new infrastructure and/or asset intervention requirement identified; and

(ii) Requirement for delivery of the scheme under the LOTI process (i.e. >£100m)

3. Efficient PCF Costs

We strongly disagree with Ofgem's assessment of efficient PCF being around 2.5% of total anticipated project costs, with expenditure higher than this being the 'exception'. Although we have seen this level of PCF expenditure for some large-scale projects in the past, our view is each scheme needs to be assessed on an individual basis given the huge variety in types, scale and characteristics of the investments.

The table below provides a summary of historical outturns for PCF projects:

ET Q12 Table 1

		Onshore			Offshore		
TO	Project	PCF (£m)	Construction cost total (£m)	PCF % total	PCF (£m)	Construction cost total (£m)	PCF% total
NGET	Hinkley-Seabank	45.9	514.7	8.9%			
NGET	Canterbury-Richborough	15.9	82	19.4%			
NGET	Western HVDC				10	719.7	1.4%
SPT	Western HVDC				10.3	331	3.1%
SHET	Caithness-Moray				15.3	1098.9	1.4%
SHET	Orkney				17.7	307.7	5.8%
SHET	Shetland				34.8	574.6	6.1%
SHET	Western Isles				17.2	640.2	2.7%
SHET	Kintyre-Hunterson				3.9	193.8	2.0%
SHET	Beauly Tomatin	4.4	118.4	3.7%			
SHET	Lairg to Loch Buidhe 132kv	5.6	57.4	9.8%			
SHET	Skye reinforcement	27.0	400.0	6.8%			
SHET	Fort Augustus 400/132kv	6.6	81.7	8.1%			
SHET	Rothienorman Substation & Rothienorman - Kintore Reconductoring	4.1	64.0	6.4%			
SHET	Fort William to Fort Augustus	1.1	61.9	1.8%			
SHET	Inveraray to Port Ann	7.9	99.9	7.9%			
SHET	Beauly to Keith OHL Replacement	2.9	62.1	4.7%			
			Weighted Average	7.9%		Weighted Average	2.8%
			Straight Average	7.7%		Straight Average	3.2%

Based on the information outlined above and our experience of the variety of scope and challenges associated with projects on our network, we highlight the following:

- The data above highlights the large variance across different historical schemes (ranging from 1% to 19%), this is also reflected in Ofgem's summary in Table 19 in the Electricity Transmission Annex;
- The construction costs associated with larger schemes (>£500m) will usually result in lower PCF percentages, this is driven by the scale of the construction costs; and
- Overhead line schemes are particularly challenging and require a significantly higher percentage PCF spend, especially considering the potential for significant challenges associated with schemes of this nature (e.g. routing options, consenting issues, stakeholders' views etc)

Our view is therefore that each project has to be assessed on an individual basis to determine the appropriate level of efficient PCF, this should be based on the project scope and associated challenges.

***ET Question 13**: Do you agree with our proposed scope of, associated eligibility criteria for, and timing of the submission window under the MSIP re-opener?*

There are two distinct parts of the MSIP: 1. The medium size connections related projects ineligible (under Ofgem's current proposals) for the volume driver mechanism and 2. The uncertain need/cost areas that emerge from third party driven need (BEIS, ESO etc).

1. MSIP connections related projects

Please also see specific responses on Volume Driver in Core Q22 and specifically our appendix "Uncertainty Mechanisms - Generation and Demand Volume Driver".

Scope and eligibility: Ofgem propose that the MSIP mechanism covers all projects priced between £25m-£100m where the costs of that project are at least double the unit cost allowances (UCAs) set for the volume driver mechanism.

We disagree with this proposal.

First, we believe the MSIP should cover all projects <£100m. Ofgem proposes we carry the risk of all projects valued under £25m under the volume driver mechanism. Setting aside other fundamental issues we have with the volume driver, the materiality of projects subject to the MSIP should no longer be set at £25m but be removed. This ensures that all atypical projects are adequately funded including system related investments and not only demand and generation connections. We do not believe the MSIP re-opener element ("ESO-driven requirements") will adequately cover system related investment but that will leave potential funding gap.

Second, we disagree that a project must reach double the allowances under the volume driver before it is classed "atypical" and can be funded under the MSIP. It would follow that for a £99m project we would be expected to carry £99m of risk (pre sharing factor) to build the infrastructure to connect generation or demand to our network (which we are obligated to do). It is an unjustified and unprecedented level of risk and with the right UM would be unnecessary to require us to take that level of risk. Previous acceptable levels of risk have been in the region of 1% of annual base revenues (c£7m for SHET in T2) for re-opener mechanisms.

Any threshold should be dependent on how cost reflective the volume driver unit cost allowances are and risk of potential over or under recovery of allowances the final volume driver model. Ofgem has not modelled the level of risk. For example, in our Business Plan we proposed this threshold would be set where costs exceed the set UCAs by 33% or more and this was informed by the extensive testing to determine the risk of potential over or under recovery to protect both consumers and company from windfall losses and windfall gains.

Timing and accessibility: a single re-opener window for MSIP in 2024 is unworkable in practice. With a window for networks to apply for funding restricted to 2024, T2 will be largely complete before the funding is approved and released. This is therefore an ineffectual mechanism as currently designed.

To illustrate, we expect the next round of CfD to take place towards the end of 2021. To enter into the CfD auction a generator must have a grid connection contract with a TO and conditions of the CfD is that the grid connection is energised in 2025/26. Yet with a window for the TO to apply for revenue adjustments to build the infrastructure for the connection restricted to January 2024, with approval therefore in mid/late-2024, the TO would be expected to invest and construct at risk (prior to approval). Another outcome would be that the regulatory process will trigger delays, the generator will be constrained and the consumer will ultimately suffer by paying constraint costs.

Ofgem should make a simple but effective change; the re-opener window for medium sized connection related projects currently ineligible for the volume driver should be removed and requests for revenue adjustments should be on an "as required basis" as set out in our Business Plan (we identified MSIP as our High Value Project Re-opener (HVTP) – see pages 81-82). This will avoid the adverse consequences set out here.

We understand that there would be an opportunity for further projects to be reviewed at close out. As noted in our response to core Q12 this needs to be made clear and transparent by Ofgem in Final Determinations.

Approval process: No process is set out for MSIP, other than a (currently unworkable) date of the re-opener window. It is important that Ofgem set this out clearly ahead of T2 commencing and consult on its proposals.

We suggest a process akin to High Value Projects in the Electricity Distribution Sector where Distribution Network Operators (DNOs) apply for an adjustment to their expenditure allowances to reflect costs that have been incurred, or are expected to be incurred by them, on any investment project that is reasonably forecast to cost £25 million or more during the price control period. It is our view that the process does not require a detailed needs case assessment but a cost assessment (similar to the Project Assessment under LOTI). The need is clearly justified by our obligation to connect; the key issue in question is why the costs of the project are atypical and therefore can't be covered under the volume driver. This focussed submission should allow a for a decision within a four month period and inclusion in the same year AIP.

Post-approval process: Ofgem propose a true-up of MSIP schemes. We disagree with an efficiency true-up as the mechanism, by design, leaves no opportunity for outperformance. By confirming deliverable outputs, we can agree to true up on what was achieved but not on efficiency. For the avoidance of doubt, those deliverables are outputs and not input targets.

In almost all cases, if not all, at the time the uncertainty mechanism/atypical scheme is reviewed and a decision is made, any cost uncertainty will be no more than that which exists when a price control is settled. That's the rationale for delaying the decision. Therefore, the TIM should apply and the allowed costs should not be subject to a true-up.

In an already dampened incentive regime to introduce cost "true-up" to a number of cost areas such as MSIP only exacerbates the dampened incentive regime we see in RIIO-T2 and the consequences of it including reduced incentives to innovate and reduced incentives to seek cost efficiencies that will form the basis of many costs for RIIO-T3 and beyond. This, we believe, is not in the long term interests of consumers.

Finally, Ofgem has set out no clear rationale why it believes these costs should be subject to an end of period true-up, with no consideration for either the proportionality of the proposed regulatory intervention nor the associated risk to licensees. It has failed to consider the risk on the TOs of a true-up *with an efficiency review* that it is considering not only for MSIP but component parts of the price control. We will provide a comprehensive view on risk in response to Ofgem's impact assessment published on 31 July by 25 September.

Consequences: There are two main consequences of Ofgem's MSIP proposals:

Cashflow impact: MSIP schemes will require SHET to spend before regulatory approval. This increases both risk and cashflow impact. Yet, this is not considered by Ofgem in its impact assessment or financeability testing (as noted we will provide this is our review of the Impact Assessment published on 31 July by 25 September 2020).

Net zero impact: The MSIP mechanism, alongside LOTI (see ET Q10) and preconstruction (see ET Q11), must be applied to a credible net zero investment scenario to demonstrate effectiveness. This has not been done and we believe it will hinder Net Zero ambitions. We set out detail on this in our response to Core Q21 and Core Q22.

2. Re-opener elements driven by third party

Scope and eligibility: we agree with the inclusion of the elements listed in paragraph 4.57 of the Electricity Transmission document but the following areas should be added/amended:

Flooding : please refer to our answer to core Q20. This should be expanded to cover "**Flooding, Wildfires & Extreme Weather**" so that alongside flood resilience requests following ETR138 guidance or a direction from BEIS, it also covers wildfires and extreme weather events.

Operational Load Management Schemes: this should not be exclusive for SPT but extended to SHET and include both inter-trips and Active Network Management (ANM) solutions. In our Business Plan we proposed a volume driver mechanism for inter-trip solutions[59] to prevent circuits overloading where generation may be reduced or disconnected following a system fault event. The volume driver would be used for inter-trips that are on a localised and interconnected network. Ofgem has not provided a view in Draft Determinations on whether it has rejected or approved our volume driver mechanism for inter-trips. SPT proposed a similar mechanism 'Operational Load Management Schemes' with unit rate proposals for ESO inter-trip schemes as part of its net zero operability challenges re-opener. Ofgem rejected this proposal but have moved SPT's Operational Load Management Schemes into the MSIP. We believe that this re-opener should apply to SHET as well as SPT as we will encounter similar STC planning requests in RIIO-T2. We further propose that this would not only cover inter-trips but also ANM solutions (another proposal in our Business Plan which Ofgem did not opine on in Draft Determinations) [60].

Shunt Reactors: we note that Ofgem is seeking further information on the costs for shunt reactors in order to develop a unit rate for the volume driver mechanism. Through the Supplementary Question (SQ) process we provided Ofgem with all of our available information. We accept that a pragmatic solution would be for Shunt Reactors to

[59] See Regulatory Framework: Uncertainty Mechanisms page 37. https://www.ssen-transmission.co.uk/media/3741/regulatory-framework-uncertainty-mechanisms.pdf
[60] See Regulatory Framework: Uncertainty Mechanisms page 37. https://www.ssen-transmission.co.uk/media/3741/regulatory-framework-uncertainty-mechanisms.pdf

move into the MSIP re-opener if Ofgem can't reach a sufficient level of confidence on the appropriate unit cost at this stage.

We disagree with the 1% materiality for MSIP. We set out our view on this in response to core Q12.

Timing and accessibility: we support a re-opener window for MSIP in January 2024 for these third party driven re-opener elements (listed in paragraph 4.57 in the ET Appendix document and above). It is not clear what Ofgem intend by a close out, but in the context of the MSIP re-opener it must provide an opportunity for licensees to recover costs incurred that could not have been foreseen in January 2024 (e.g. ESO driven work). These costs are third party driven and is perfectly reasonable that intervention could be required prior to the close of RIIO-T2.

Approval process: No process is set out for part 2 of the MSIP, other than the re-opener window. It is important that Ofgem set this out clearly ahead of T2 commencing and consult on its proposals. As with other re-openers there are significant outstanding questions on how they will work in practice. We note that there are some promises of guidance documents to follow but it is not clear when that will be and what that guidance will contain. We ask that Ofgem:

- set out a clear guidance document for the MSIP and when it will be provided;
- within that guidance set out that it will undertake decision-making in time for the Annual Iteration Process (AIP) in 2024; and
- provide a clear commitment to reach a decision within six months of submission. We fully acknowledge that there is an onus is on licensees to make high quality submissions. This also places emphasis on a clear, transparent and timely guidance document.

We would expect that the re-opener in January will allow for cost allowances that are both backward and forward looking (where possible) for the areas listed in paragraph 4.57 in the ET Appendix document and above. We would expect that the close will allow for backward adjustments.

Post-approval process: Ofgem propose a true-up of MSIP schemes. All of our points noted above for part 1 of MSIP apply here. While there will be some unusual events where need has become certain, costs can vary. We should treat these as the exception. We believe all the items listed under part 2 of MSIP should be capable of being cost certain at the time of the re-opener decision.

4 SHET Annex: consultation question responses

SHET Question 1: *Do you agree with our proposals on the bespoke ODIs? If not, please outline why.*

SHE Transmission did not propose any bespoke financial ODIs[61]. We focused on our Consumer Value Proposition (CVP) and delivering ambitious initiatives which demonstrated consumer value. All of our CVP proposals, as outlined in response to SHET-Q4 (and SHET-Q5 for biodiversity net gain (BNG)), have clear deliverables to ensure the ambitious initiatives proposed are delivered. To ensure accountability of delivery we have proposed this is reported to both our new User Group 'A Network for Net-Zero Advisory Group' (see response to Core Qs 1-5) and as part of our enhanced annual reporting to wider stakeholders (see page 103 of our Business Plan for our Enhanced Reporting Framework). If these initiatives are not delivered, we are supportive of the clawback mechanisms as outlined in response to Core Q38.

We welcome Ofgem's draft decision to approve the ODI-R for both ITOMs and ITAMs. We agree with the administrative light touch to this incentive and will include these as part of our enhanced annual reporting to stakeholders. However, please note that like other policy areas this is only deliverable if we have the resources to do so. Please see our response to SHE-T Q10 which outlines the adverse policy impact of Ofgem's proposed unjustified cuts, including to our Closely Associated Indirect (CAI) costs.

We have also proposed NGET's bespoke ODI based on an Environmental Scorecard is consistently applied across all TOs to become a common ODI. Please see our response to ET Q6.

SHE Transmission originally proposed one bespoke ODI based on customers' experience in connections. This is now a common ODI under the Quality of Connections (Please see ET Q1 and ET Q2).

SHE Transmission did not propose an ODI associated with ESO-TO system access, please see our response to SHET Q2.

[61] ENS is described as a bespoke ODI in Table 10 of SHET Annex – but as common on p152 of SHET's BP.

***SHET Question 2**: Do you agree with our consultation position to reject the 'RIIO-T2 System Outage Management Proposals to Reduce Constraint Costs'?*

We have noted in our response to SHET-Q4 the consumer value in reducing constraints in our Network Access Policy CVP (CVP 2B) and the disagreement with Ofgem's draft decision to reject this CVP.

The TOs and ESO provided Ofgem with an informal proposal on the 'RIIO-T2 Outage Management Proposals to Reduce Constraint Costs' to seek feedback from Ofgem ahead of Draft Determinations. Between the joint TO informal proposals and SHE Transmission's CVP 2B we believe there is consumer value to incentivise TOs to provide whole system solutions to reduce constraints. Although the NAP KPIs will provide information to indicate performance improvements, there is no incentive for TOs or ESO to change behaviour to improve performance.

For TOs, having a NAP is a special license condition to which there are no financial incentives attached. For NGESO, they do have an incentive scheme but it is now against a very broad range of measures, one of which is system operational costs. The new NAP KPIs will better demonstrate how each TO is complying with NAP principles of having a safe and reliable network, as well as efficient outage planning, but there are still no direct financial incentives. This is evident from the lack of STCP 11.4 changes put forward[62]. Without an incentive, in addition to the efficiency savings applied by Ofgem, there will be limited scope for TOs to provide any enhanced services above licence conditions due to demands on resource.

[62] TO Enhanced Services were introduced as a trial in 2018, then officially in 2019 via STCP 11.4. Only one change has been put through via STCP 11.4 by SPT. This was only a small amount of a few thousand pounds which will eventually save £millions.

SHET Question 3: *Do you agree with our proposals on the bespoke PCDs? If not, please outline why.*

We answer this question in two parts. The first is on the question that was asked regarding SHET's bespoke PCDs and the second we provide views on the PCD framework.

Part A: SHET bespoke PCDs

As Draft Determinations stand, we broadly agree with the proposals on PCDs. However, we note that Ofgem rejected the following PCDs:

- **Reliability – Digitalising the network:** we proposed the installation of smart monitoring at 62 critical assets and establishing real time asset analytics at a dedicated control room.
- **Redundancy – back up assets:** we proposed two large warehouses with best practice inventory management.
- **Faults:** we proposed to reduce the average annual number of unplanned interruptions, of all durations, with no exclusions from 131 to 72.
- **New CBA Framework:** we proposed using a new Cost Benefit Analysis (CBA) framework for the evaluation of new investments from 1 April 2021.
- **Stakeholder Engagement Commitment:** we proposed surveying all our stakeholders using KPIs to measure performance and achieve AA1000 Health Check.
- **Diversity and inclusion**: train >95% of our employees in diversity and inclusion.

However, there are two important caveats to the above.

For the first two, the baseline funding associated with these has been rejected in Draft Determinations and it follows that the associated PCDs should be removed. However, we have presented revised evidence for our Integrated Condition Performance Monitoring[63], Operations Centre[64] and Materials Management and Warehousing[65] within the relevant revised and additional Engineering Justification Packs (EJPs). We are confident that Ofgem will approve these projects and in doing so we propose that these PCDs are reinstated for Final Determinations.

For the remaining four proposed PCDs, these were proposed following engagement with stakeholders.

- On **faults** we proposed this to assist stakeholders with understanding network reliability, as ENS is a metric not easily understood by energy consumers. We will continue to report on this for our stakeholders even if not classified as PCD as Ofgem has provided the baseline funding.

[63] T2BP-EJP-0012 Integrated Condition Performance Monitoring Justification Paper and T2BP-EJP-0050 Dynamic Line Rating Engineering Justification Paper (Note: ICMP has had the Dynamic Line Rating component broken out into a new paper).
[64] T2BP-EJP-0003 Resilience - Operations Centre Justification Paper
[65] T2BP-EJP-0013 Materials Management and Warehousing Justification Paper

- On the **CBA framework**, this arose from the development of our Sustainability Strategy and a desire from stakeholders to see how environmental and social costs and benefits were transparently incorporated into our investment decision-making process. Again, we will continue with the development even if not classified as PCD as Ofgem has provided the baseline funding (subject to addressing the cut to Closely Associated Indirect (CAI) costs) – see point below.

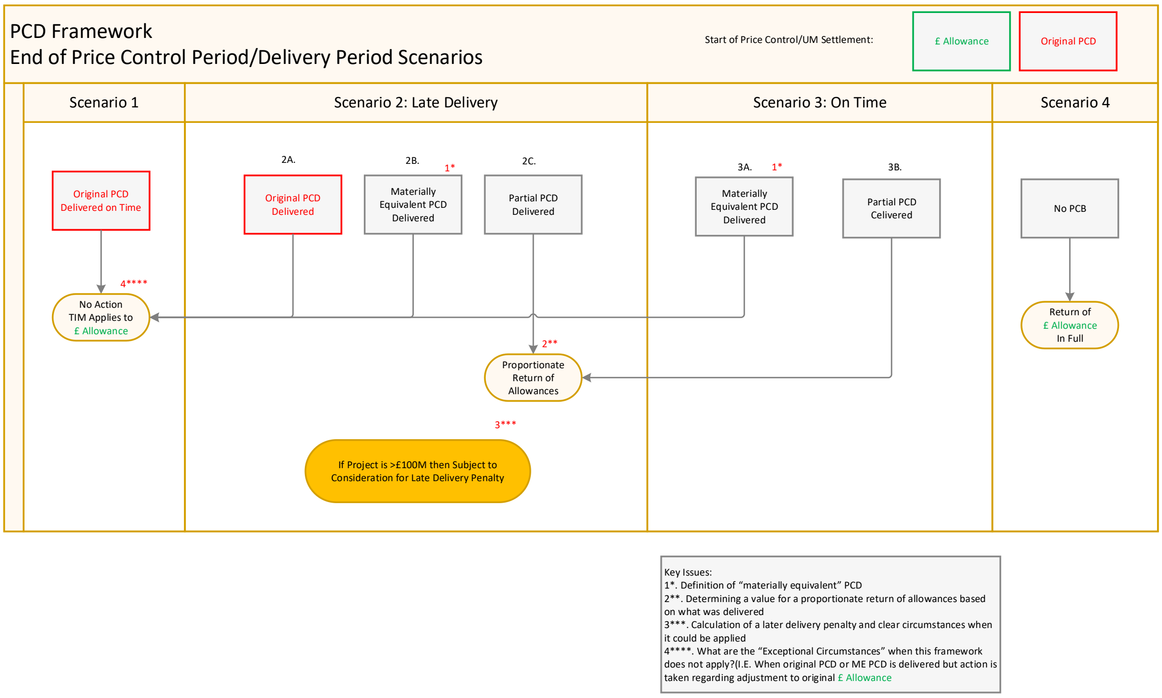
- On the **Stakeholder Engagement** and **Diversity and Inclusion** PCDs, while we accept these not being classified as PCDs, both are areas that are important to our stakeholders. Both will be subject to our Enhanced Reporting Framework (see page 103 of our Business Plan) and we commit to their delivery for our stakeholders. **However, our commitment is on the provision that we have the necessary baseline funding to deliver both.** As noted in response to SHET Q10 Ofgem has proposed a £93.9m (37%) to our overheads despite our independent analysis demonstrating we are efficient. Setting aside our clear position that this is an error, these overheads included baseline are necessary to deliver these activities. The severity of Ofgem's proposed cuts puts delivery of these outputs and others at risk.

Part B: PCD Framework

Ofgem's PCD policy is unclear, there is no established PCD framework, in particular it is not clear how Ofgem has incorporated the express views of stakeholders into its decisions about appropriate PCDs. Similar to the re-openers (see core Q12), there are significant outstanding questions about the practical application of the PCD framework. We note that Ofgem circulated updated guidance to licensees on the PCD framework on 27 August 2020 but there has been insufficient time to reflect this in our response to Draft Determinations.

This is an issue which we believe would benefit from an update on Ofgem's position prior to Final Determinations to allow for informed comment from stakeholders. This is critical to our understanding of the proposed settlement, our expectations of what outputs are funded to be delivered and how substitution methodologies will work. In this context, we highlight that the PCD framework should enable delivery of more effective and innovation solutions for outputs that might be identified within the price control period.

The diagram below sets out our view of the PCD framework and application.



The following is necessary to ensure the PCD framework works in practice for the start of RIIO-T2.

PCD framework: Ofgem set out a clear PCD framework, in consultation with licensees, so both licensees and stakeholders are clear on expectations and consequences. The licence consultation should follow this and not pre-empt this. Ofgem should also publish a full list of all guidance documents and a timetable for when each will be provided.

Exceptions to the framework: the relevant licence condition should be explicit that the PCD framework is the framework to which licensees will be held accountable and **only in exceptional circumstances** will Ofgem deviate from this (see our point below on secondary deliverables). The wording on this point is critical to avoid a move from output to input based regulation. It therefore follows that "exceptional circumstances" must be clearly and explicitly defined.

Definitions: the licence should clearly define the following terms for each individual PCD:

- Materially equivalent
- Late delivery
- Partial delivery

Methods: within the licence, methods for calculating a proportionate return of allowance should be clearly articulated.

Interactions with and separation from other policies: within the framework guidance it should be clearly articulated how PCDs will interact with any proposed late delivery mechanism. For the avoidance of doubt, we do not support late delivery penalties (see ET Q4 and 5). We are further concerned that late delivery policy is being extended by Ofgem to cover all PCDs and not only Large Project Delivery (LPD) (i.e. Projects >£100 million). Ofgem, has never discussed or consulted on its application beyond the scope of LPD. To do so would be inappropriate given the additional risk this would add to the price control.

Exceptions to the Framework and Secondary Deliverables

A core principle of setting a framework is that deviation from it should be the exception and not the rule. Further, the **exceptions must be clearly set out**. Failure to do so could have unintended consequences and add risk for the licensee.

We note on page 17 of SHET's Draft Determination annex that in additional to our PCDs for two large capital projects - East Coast 275kV and NE400KV – Ofgem has set a "secondary deliverable" for each as "scope of works as presented in the relevant EJP". There is no further explanation in the document on what this means or the rationale for their inclusion, nor were there any policy discussions on the possible introduction of "secondary deliverables".

We have significant concerns via the statement "scope of works as presented in the relevant EJP". It is alarming as change to scope may be necessary to accommodate new connection applications, new technologies and costs efficiencies benefiting consumers. We don't believe this can be Ofgem's intention. The SSMD made reference to linking "certain PCDs to licence conditions to help ensure that consequences for failure to deliver, late delivery, or *delivery to a lower than expected standard are specified* [emphasis added]."[66] We understand that it would be unacceptable to deliver a PCD (e.g. additional MVA capacity) in a manner that would result in material compromises for the network, for example with regards to resilience or reliability. However, this is a very different prospect to delivering exactly the scope as set out in the EJP.

Ofgem must be clear on its policy intent with secondary deliverables. It should remove the requirements for "scope of works as presented in the relevant EJP" and set parameters, in conjunction with the licensees on the standards expected. This needs to be proportionate and focus on what has changed and the impact of that change. We expect Ofgem to engage fully with licensees in developing this PCD framework and exceptions to it.

[66] https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_core_30.5.19.pdf paragraph 4.30

SHET Question 4: *Do you agree with our proposals on the CVPs? If not, please outline why.*

Summary

As a general comment, we consider that Ofgem's application of the CVP fails in the policy intent to reward ambition: it is telling that out of 117 CVP proposals put forward by network companies (with a total value of over £5.5bn), only two were granted a reward (calculated by Ofgem at only £1.6m each). Our biodiversity CVP was accepted in principle by Ofgem, but Ofgem has disputed the valuation methodology without proposing or engaging on an alternative. For this to emerge systemically across the network sectors is not down to a lack of ambition or evidence on the part of the licensees, particularly given the User Group and Customer Engagement Group support for CVPs.

Ofgem's lack of guidance on CVPs meant that network companies were putting forward proposals against an evidential bar which was unclear. Despite the poor guidance and evolving picture, we took a clear strategic approach to the CVP, identifying initiatives, ensuring that such initiatives were above BAU, ensuring stakeholder (including User Group) support, providing robust supporting evidence for each initiative, providing a monetisation where possible and committing to returning any reward for outputs not delivered (see response to core Q37). In doing so, we proposed justifiable and evidence-based CVPs for only the aspects of our Business Plan that proposed to go above-and-beyond the minimum. Despite this thorough and rigorous approach, Ofgem failed to recognise our ambition, except for in biodiversity, and in doing so has failed to follow through in its policy of rewarding ambitious and high quality plans.

We set out a detailed response to Ofgem's Draft Determinations position on our CVP in this response to SHET Q4 and SHET Q5. We have engaged further with Ofgem and stakeholders during the consultation period and so described here is our revised position in three key areas in response to Ofgem's feedback:

1. **Biodiversity Net Gain (CVP 3A):** We strongly agree there is clear value in aiming for BNG in our RIIO-T2 projects. We have been led by stakeholders in setting our targets for RIIO-T2, ahead of both regulatory and legislative change in Scotland. In response to Ofgem's decisions we proposed several alternatives to valuing BNG including taking our own initiative to engage with NGET TO. Despite efforts to come to an agreed approach there's been limited direction from Ofgem and we are advised that this will now take place after 4 September. Nonetheless, we will continue with engagement to reach a position. Therefore, for the purposes of this response we have been unable to provide a revised value for BNG.
2. **Commercial and Connections (CVP 2):** Connecting renewables is our BAU. However, our CVP outlines how we can transform our role as a TO that reacts to customer requests for connections to a customer centric business beyond the BAU. This approach was co-created with our stakeholders including our User Group. Our services are intended to stimulate the engagement, connect low carbon technologies quicker, open opportunities for new entrants to connect renewables (such as local and community generation) and ensure our customers get the most out of their connection based on their evolving requirements after they are connected. Our policy initiatives in this space are ambitious, bold and industry leading. They are beyond minimal requirements and essential to delivering Net Zero. For the purpose of monetizing the value, we have revised our previous CVP submission of three distinct CVPs (CVP 2 A, B and C) and combined into one simplified CVP. Responding to Ofgem's concerns in the Draft Determinations, we used an evidence-based approach to monetise the impact based on our RIIO-T1 track record to forecast potential impact on RIIO-T2 to respond to Ofgem's feedback. We have proposed a revised the value for this CVP (2) as £12.8m.

3. **Science Based Target (CVP 6):** We are the world's first network operator to set a science-based (SBT) target in line with the Paris agreement at 1.5°C warming which is consistent with a net zero pathway. This is above Ofgem minimum requirements that require an SBT at a minimum 2°C scenario to be set. We have set a high standard and benchmark for other to follow. This ambition has not been recognised by Ofgem. We presented this as a qualitative CVP in our Business Plan, which we have now monetised to provide Ofgem with the evidence it feels it requires to justify a reward. Although monetisation is not a pre-requisite for a reward,67 Ofgem has focussed solely on a quantitative approach whereby only elements that can be monetised are considered for a reward. We are not waiting until the start of RIIO-T2 to set our SBT nor have we gone for the minimal option. Effort and action taken now will have a permanent benefit to future consumers. We have proposed a revised the value for this CVP (6) as a range of £3.6m to £8.7m.

We also note that our ambition in supporting local supply chains (£6.4m) and our network interruptions schemes have not been recognised. Again, both initiatives, although one qualitative in value, are beyond minimal requirements, supported by stakeholders and demonstrate consumer value. At a minimum this additional value should be recognised (e.g. by not automatically choosing the lowest CVP value in the other areas listed above where there is a range).

Our CVP, despite minimal guidance from Ofgem, provides a package of initiatives that demonstrate the ambitious and innovative nature of our Business Plan in delivering a network for net-zero. The changes that we make today have a demonstrable permanent value for future consumers whether that's displacing carbon off the system quicker, taking an ambitious target to reduce our own GHG emissions or leaving the environment of our sites in a better state than when we arrived. We have taken an evidence-based, robust approach to value only those initiatives in which we have set our self a real challenge beyond the BAU or minimal requirements. We believe this meets the policy intent (as discussed in response to Core Q37) of the CVP to incentivise monopoly network operators.

The below table summarises our response. Including references to areas of further detail in this response and others.

SHET Q4 Table 1 SBT CVP

CVP	Ofgem Draft Decision (summary)	SHE-T Response
1A Reducing risk of consumer overpaying - Certain View and output return commitment 1B Reducing risk of consumer overpaying - Volume driver unit cost allowance	**Reject:** The proposed CVP benefits both TOs and consumers; unclear why this warrants a reward.	We believe the UMs we have proposed and continue to develop are efficient and save consumers' money. We rely on the evidence put forward in our Business Plan (CVP 1 A and CVP 1B) to demonstrate the value of this CVP.
2A Connecting for society - commercial	**Reject:** concerns regarding the methodology for	We **disagree**. Our stakeholder engagement demonstrates that this CVP is above BAU, delivers

[67] https://www.ofgem.gov.uk/system/files/docs/2019/10/riio-2_business_plans_guidance_october_2019.pdf . On page 53 Ofgem state "where *possible* this evidence should be quantitative" [emphasis added] but this does not exclude a CVP being rewarded.

and connections service	monetising the CVP and its delivery, including potential contingence with original targets. Also noted the QoC incentive may already drive this behaviour.	consumer benefits through quicker, more efficient and accessible connections. The type of behaviour proposed to be incentivised under the CVP is above beyond that of the QoC. The QoC incentive is aimed at network users (connection customers) whereas our CVP is aimed at consumers and societal benefits.
2B Connecting for society - local and community energy policy	**Reject**: detail of initiatives unclear. BAU under RIIO-T1.	Where requested additional information on initiatives and above BAU performance are detailed. Following Ofgem's feedback we have proposed **an alternative methodology to monetise the value of this CVP focusing on RIIO-T2.** This simplifies and combines CVP 2A, B and C into one monetised CVP focusing on displaced carbon. We have proposed a revised the value for this CVP (2) as £12.8m. Explained in more detail below from section 'CVP 2'.
2C Connecting for society - Above BAU in whole system network: Network Access Policy	Reje**ct:** the NAP is minimum requirements. Methodology to quantify benefit is unclear. Already covered under proposed ODI-F. Unclear on stakeholder support**.**	
3A Promoting the natural environment Biodiversity Net Gain (BNG)	**Accept:** Value to be determined.	We **strongly support** Ofgem's Draft Decision. However, there is no industry standard methodology for monetising BNG. For the purposes of monetisation of this CVP only we will continue to endeavour to engage with Ofgem and other TOs ahead of Final Determinations. This is explained in response to SHE-T Q5.
3B Promoting the natural environment VISTA	**Reject:** VISTA does not go beyond minimal requirements. WTP data does not provide sufficient justification. Insufficient stakeholder support**.**	We believe there is potential consumer value. We rely on the evidence put forward in our Business Plan (CVP 3B) to demonstrate the value of this CVP. However, we acknowledge this requires further development with our stakeholders.
4: Supporting local communities: local supply chains	**Reject:** considered BAU and corporate responsibility.	We **disagree**. Our plans to support local supply chains (meet the buyer events, Open4Business portal and project reporting of local spend) are not BAU activities. Other TOs are not undertaking similar activities to promote local supply chains. We have not requested baseline funding for these activities so there is a consumer / local community value for these activities. We rely on the evidence put forward in our Business Plan (CVP 4) to demonstrate the value of this CVP
5: Sector Leading Efficiency Early engagement	**Reject**: considered as BAU.	We believe our engagement has delivered significant efficiency savings for consumers. We will continue this engagement in RIIO-T2. We rely on the evidence put forward in our Business Plan (CVP 5) to demonstrate the value of this CVP
6: Tackling climate change - Science Based Target	**Reject:** considered as BAU.	We **disagree** with the proposed rejection of this CVP. We are the world's first network company to set a science-based target, in line with the Paris agreement at 1.5°C. This ambition has not been recognised by Ofgem. To demonstrate the consumer value, **we have proposed monetising** this

		reward. We have proposed a revised the value for this CVP (6) as a range between £3.6m to £8.7m of consumer benefit. See section 'CVP 6 Science Based Target' of this response for further detail.
7: Safe and Reliable Network Interruptions compensation scheme	**Reject**: Continuation of RIIO-T1, unclear how this provide additional value in RIIO-T2.	We **disagree** with the proposed rejection of this CVP. Our proposal for this compensation scheme is above BAU given no other TO has such a scheme. The consumer benefit of our proposals has not been recognised in the draft decision. We rely on the evidence put forward in our Business Plan (CVP 6) to demonstrate the value of this CVP
8: Supporting local communities: Supporting vulnerable customers	**Reject**: considered as BAU.	Ofgem's SSMD states TOs do not need to consider support to vulnerable consumers as BAU - the Draft Determinations is an unexpected change in this position. Including our actions to support vulnerable consumers within the Business Plan incentive will encourage further action to support vulnerable consumers through a coordinated approach DNOs, local authorities and other agencies. However, we note that these actions may be **included in the proposed community fund** (see response to SHE-T Q6).

It should be noted that without a CVP reward alongside the baseline funding required to deliver the CVP initiatives (mainly through CAI costs see response to SHE Q10) we will not be able to deliver our CVP proposals. We are committed to being accountable for our CVP proposals (see Core Q38). Any reporting or commitments outlined in this document are conditional on baseline funding and a CVP reward is granted in final determinations.

As noted above, the remainder of this response details a revised monetisation of benefits for two CVP proposals:

- **CVP 2:** Connecting for Society Commercial and Connections Services (which now includes CVP 2B and CVP 2C) which has a revised methodology to respond to Ofgem's feedback and focuses solely on carbon displacement RIIO-T2 projects

- **CVP 6**: Tackling climate change - Science Based Target which has a new quantitative consumer benefits rather than qualitative in our Business Plan, again responding to Ofgem's feedback that this is above minimal requirements and provides additional value to consumers.

CVP 2A: Connecting for Society Commercial and Connections Services

We strongly disagree with the proposal to reject CVP (2A) and it remains our view that these proposals are **beyond business as usual** and drive significant consumer value. Our view is substantiated by precedent, an evidence-based approach from RIIO-T1 experience and stakeholder support. **Our CVP 2 is a set of tangible ambitious actions which can drive net-zero outcomes.**

We are concerned with the **limited feedback from Ofgem on our proposals**. However, we have responded to Ofgem's feedback in its Draft Determinations for each of our CVPs following our Five

Stage Approach to CVP (see our response to Core Q37). Following further engagement with Ofgem we have set out an alternative approach to monetising CVP 2.

This is described below, but first it is important to note that there is **precedence for awarding carbon displacement**.

There is clear precedent for supporting carbon displacement throughout the GB energy market, through a mix of policies (including taxes, subsidies, standards and regulations) all of which aim to reduce GHG emissions[68]; a core objective of many of our stakeholders For example, there is a clear precedent for government subsidies to encourage low carbon generation through schemes such as Contracts for Difference[69]. Throughout the electricity value chain, all providers should have aligned incentives to promote low-carbon energy including transmission companies such as SHE Transmission who look to enable and accelerate more low carbon generation above BAU.

Ofgem had debated, including with commentators via a guest blog, an explicit RIIO-2 low carbon incentive[70]. This was not pursued. The CVP framework embodies some of the thinking behind through awarding ambitious Business Plans (see our response to SQ 37) and Ofgem's SSMD (see section 3.6) also acknowledges the importance of encouraging low carbon transition when considering ODIs: "*Company driven target signifies an output where we expect to see extensive company-led engagement (including with their UG) to justify a stretching performance target. This could lead to performance targets varying by company."*

There is also precedent in Ofgem's decision making for providing upfront funding and for upfront rewards like the CVP:

- In RIIO-1, Ofgem allowed LCN Tier 2 Funding of £7.62m for SP distribution (SPD)[71]
- In RIIO-2, Ofgem has allowed SP Transmission (SPT) a CVP reward in relation to community renewables

The RIIO-1 SPEN project related to Accelerating Renewable Connections (ARC). SPD describes as follows: "*The ARC project aimed to address these issues by creating and demonstrating a range of technical and commercial solutions for accelerating renewable connections in a controlled manner to avoid the network from being a barrier to the transition to a low carbon economy*[72]."

The ARC project aimed to address these issues by creating and demonstrating a range of technical and commercial solutions for accelerating renewable connections in a controlled manner to avoid the network from being a barrier to the transition to a low carbon economy. Both the SHE Transmission

[68] Catapult 2019, Rethinking Decarbonisation Incentives: Future Carbon Policy for Clean Growth, June.
[69] Alongside others such as the Feed in Tariffs and Renewables Obligations Credits See, for example: House of Commons 2016, *Energy: The Renewables Obligation*, Briefing Paper, July; and https://www.ofgem.gov.uk/environmental-programmes/ro/about-ro
[70] https://www.ofgem.gov.uk/news-blog/our-blog/guest-blog-future-fit-new-low-carbon-incentive-riio-2
[71] A further £0.84m was invested by SPD with some additional contribution from project partners, bringing total project funding to £8.46m.
[72] SP Energy Network 2017, *Accelerating Renewable Connections (ARC): ARC Closedown Report*, March

and SP ARC projects concern accelerating connections to enable and accelerate connections through commercial and policy solutions thereby avoiding carbon.

More recently, in RIIO-2 Ofgem proposes a reward of £1.6m to SPT for one CVP proposal to provide land (at no charge) to community groups to install 4MW of renewable generation. Ofgem accepts that this will 'deliver additional environmental benefits for current and future consumers at minimal cost[73]'. Importantly, both SPT and SHE Transmission's CVP's have a permanent impact on carbon avoidance.

Stage 1: Minimum Requirements +

Our Commercial and Connection Policy was co-created with our stakeholders during the development of our RIIO-T2 Business Plan.

A specific policy or focus on Connections customers was **not part of Ofgem's minimum requirements**, however we recognised the importance in connections customers in achieving our strategic objective of enable the transition to a low carbon economy. We also note network users being central to Ofgem's RIIO principles.

The new services outlined in our RIIO-T2 Business Plan go beyond the traditional role of the TO which, as outlined in our licence and industry codes, has an indirect customer relationship **to the new customer centric role which we have proposed**. We outlined in our response to Ofgem's SQ (18 and 25) the transformative nature of the twelve new products and service to be introduced from RIIO-T1 to RIIO-T2. This includes enabling customer collaboration to make efficient use of our network, engaging with customer earlier in the connection process to make better informed investment decision and enable innovative whole system approaches.

This innovative approach is industry leading, ambitious yet essential to deliver net-zero. This approach is not BAU as indicated by Ofgem in its Draft Determinations but a **behavioural, organisational and cultural change**. This is an area we believe requires incentivisation under the CVP to deliver this change and to incentivise the continuous adaptation of services and products to meet customers' needs and drive consumer value throughout RIIO-T2. **The accountability and delivery of this incentive via the CVP Clawback mechanism (see response to Core Q38) will ensure this change is delivered.**

Stage 2: Stakeholder Support and consumer value

We welcome Ofgem's acknowledgment that there has been stakeholder support in this area. We were led by our stakeholders in this area and co-created proposals with them, listening to their challenges and proposing new innovative products and service to address challenges. This co-creation included our RIIO-T2 User Group. The group challenged us to be more ambitious in connections and as a result supported endorsed our CVP in this area[74].

We recognise that timely connection of renewables is our Business as Usual. We also recognise that we have demonstrated evidence that we can deliver **connections quicker during RIIO-T1** when

[73] Ofgem 2020, RIIO-2 Draft Determinations – Scottish Power Transmission, July, p.13 and 15.
[74] See Page 13 of the User Group Report

reacting to a customer request. Arguably this **is not Business as Usual across TOs** as noted in Ofgem's decision in response to NGET's lack of baseline data in their ODI proposal.

Our RIIO-T2 proposals **do not simply replicate and repeat the activities from RIIO-T1**. As outlined in our response to SQ 25, accelerating connections will become increasingly **challenging** due to the **new types of customers and variance in customers size**. This requires a tailored connections service to provide each customer the most optimal connection including us becoming more **proactive** with customers throughout their connection life and customer experience. There is consumer value in our proposals from tailoring our connections service by providing a **more efficient service, getting the most out of our existing network from collaborative whole system approaches.** This tailored approach also ensure that the connection process is as **accessible** as possible for new customers.

Overall, our new connections services will result in **new connection customers, quicker connections and more efficient use of our system**. This type of service demonstrates the **critical role of the TO in delivering a network ready for net-zero**. This CVP illustrates **ambition, innovation and delivers the policy intent behind Ofgem's proposed CVP** (as outlined in response to Core Q36).

These benefits are separate from the Quality of Connection incentive which is aimed at connection customers, this CVP **outlines consumer and societal benefit alongside ambition of our Business Plan**.

Stage 3: Monetisation

We note Ofgem's concern with the methodology for monetising this CVP. Monetising the above consumer value is challenging, however we reasonably proposed a proxy of carbon displacement. The methodology is based BEIS/Grid mix for UK electricity that as more renewable technologies are connected, carbon is displaced on the system. This is based on Green Book standards. It should be noted that SPT have used a similar methodology for their approved CVP 'Maximising environmental benefit from non-operational land'[75].

Our methodology has used an evidenced-based approach from RIIO-T1, assessing projects which have connected quicker than the date in their original connection offer. This resulted in projects being connected 131 weeks (36%) quicker than originally anticipated. As outlined in response to SQ 31, the reasons for this acceleration was non-firm arrangements or the acceleration of works from the TO rather than primarily driven by external factors. Grants are also available for renewables, including in Scotland.[76] The Scottish Government is also now making available additional funding of £5.5 million for renewables projects to contribute towards the Green Recovery following the coronavirus (COVID-19) pandemic.[77]

Revised approach to CVP 2:

We believe we have applied a rigorous evidence-based approach within this methodology which resulted in £59.5m of consumer value. However, we have considered the feedback from Ofgem that our CVP is based on RIIO-T1 activity. Following this feedback, we have challenged **ourselves to demonstrate the additional benefits to be delivered in RIIO-T2.** We have made the updates to our methodology as set out in Table 2.

[75] Ofgem 2020, RIIO-2 Draft Determinations – Scottish Power Transmission, July, p.13 and 15.
[76] https://www.gov.scot/policies/renewable-and-low-carbon-energy/local-and-small-scale-renewables/
[77] https://www.gov.scot/news/supporting-the-green-recovery/

SHET Q6 Table 2: Revised assumptions

	Business Plan	New Draft Determination Proposal	Why did we change this assumption?
Methodology	Displaced carbon from accelerated connections		This is unchanged. This is a tangible demonstration of benefits that can be delivered now to deliver net-zero. Based on robust methodology and precedent.
Projects	Based on RIIO-T1 average	Based on our current likely view only	To demonstrate the benefit of stimulating the pipeline of projects in our current likely view rather than those we are certain will connect (in our certain view)
Acceleration rate	RIIO-T1 average: 131 weeks	RIIO-T2 improvement rate: 10% (144 weeks) – RIIO-T1 counterfactual (131) = **13 weeks**	To demonstrate above BAU RIIO-T1 performance. We have removed the counterfactual and included the **10% increment only**.
Assumption of acceleration	Average used from RIIO-T1	**50% of likely view projects** = 7 projects	All projects will benefit from our connections initiatives. However, we've made the conservative assumption only half will accelerate.
Inclusion of other benefits?	No. Separate CVP for whole system efficiency (CVP 2B) and constraint savings (CVP 2C).	Yes. Includes benefits from CVP 2 B and C.	Although whole system and constraint saving benefits were quantified separately in our Business Plan these will be delivered as part of the overarching Commercial and Connections Policy. They also have the same benefit of displacing carbon. Packaging the proposals will deliver the same consumer benefits but via a simplified methodology for the purposes of the CVP reward.
Delivery of CVP	Via KPIs reportable to our new User Group and enhanced annual reporting.		Assumptions in our methodology have changed. Delivery and accountability of the CVP remains unchanged.

We note that changes in the prevailing policy background since we submitted our final RIIO-T2 Business Plan in December 2019 have strengthened the route to market for renewable generators in the north of Scotland. In particular, the UK Government proposals to reform the CfD auction to allow onshore wind to compete in 'pot 1' and for remote island wind eligibility. Following this, we have **experienced a significant volume of new or modifications to connection applications**. With a strict timetable for CfD auction and delivery years, tailored connections services are critical to our customers. **We have updated our CVP calculation for our current likely view of connections over-and-above the Certain View**.

Table 3 below demonstrates the actual consumer benefits of the Commercial and Connections CVP 2. This includes **8.7MtCO2e and over half a billion pounds (£638m) of consumer benefit.** However, we are **not** proposing this is our CVP value. As outlined above we have taken a conservative approach to our revised CVP methodology, once we have applied our revised assumptions results in **£12.8m**. As outlined in our response to core Q37 this is the proposed value to consumers, not the proposed CVP reward. **CVP value does not have to equal CVP reward.**

Please see analysis attached in T2BP-DD-SHE-013 SHET Q4 Annex 1.

SHET Q6 Table 3: Revised CVP 2

	Actual benefits	Revised CVP Proposal**
Scope	Certain View + Likely Outturn Projects	Current likely view Projects only
Accelerated Connection Time	144 weeks (RIIO-T1 average + 10% improvement)	13 weeks (10% increment only)
Carbon Displaced	8.**7** MtCO2e	0.3 MtCO2e
Consumer Value	£626.4m+ £5m (CVP 2B) +£6.6m (CVP 2C) = £638m	£25.5m+£0
CVP value (with 50% connection assumption)	c. £319m	c. £12.8.m

<u>Stage 5 – return commitment</u>

(NOTE: we move from Stage 3 to stage 5 as stage 4 refers to consideration of qualitative CVPs)

We note Ofgem's concerns that the proposed measure of delivery of this CVP may be affected by contingency built in the original target. We are **confused by this assessment** as we have proposed a KPI approach rather than an approach based on acceleration target as outlined in response to SQ 25 and SQ 40. In this response we make the case that to deliver the commercial and connection policy outcomes is beyond just accelerating connections, other benefits such as enabling more connections and efficient connections are more difficult to measure. The innovative nature of this approach and measuring the delivery is similar to that recognised in a guest blog from Ofgem which proposed a qualitative approach under-pinned by metrics [78]. We have included the proposed KPIs below. For our response to the return commitment please see Core Q38 response.

Proposed KPIs (SQ 25 update):

At this stage we propose both quantitative and qualitative metrics. **We welcome feedback and engagement with Ofgem on how to best measure delivery of the CVP.**

We propose to measure the **activities** we are conducting that will specifically accelerate connections (note point 4 below). We will collate these in an annual report as part of our Enhanced Reporting and to our Network for Net Zero Stakeholder Advisory Group (i.e. the continuation of User Group - see our response to Core Q 1-5 for further detail). Alongside reporting the numbers, we will also provide the qualitative evidence to demonstrate we are committing to provide a service that is bespoke to customers' needs.

[78] https://www.ofgem.gov.uk/news-blog/our-blog/guest-blog-future-fit-new-low-carbon-incentive-riio-2

Moving beyond activities, the key **outcome/impact** measures will be:

- the difference between the originally agreed connection date and the new accelerated date; and
- where the above isn't possible, the difference between a counterfactual date (i.e. without our service or intervention) and the actual connection date.

This difference will then be used to calculate the displaced carbon in the same way as per our CVP. That is:

- identified the additional renewable generation capacity of each customer (MW);
- applied a load factor appropriate to the renewable technology using the Scottish Renewable Output Calculator – converting the capacity (MW) to (MWh);
- calculated the carbon based on BEIS/Grid mix for UK electricity; and
- applied a carbon price for relevant year to calculate the carbon cost.

Suggestions are set out below:

What is being measured?	Unit	Quant/Qual	How	Accountability
Activity Measures				
Provision of live map/up to date	Yes/No	Qualitative	Record in real time and report annually	Enhanced Reporting Framework, Network for Net Zero Stakeholder Advisory Group
Offer in principle Queue Management (total) Incl. acceleration Incl minor modification Renew Product	Volume of users Story of changes/accelerations requested, how we have responded	Quantitative and qualitative	Record in real time and report annually	Enhanced Reporting Framework, Network for Net Zero Stakeholder Advisory Group
Outcome Measures for each connected customer				
For each connection – connected on time	Yes/No	Actual connection date vs Agreed planned connection date	Record in real time and report annually	Report to Ofgem annually (RRP) and part of Close Out. Enhanced Reporting Framework and Network for Net Zero Stakeholder Advisory Group.
For each connection – early (at the customers' request)	Original connection date	Quantitative		
Outcome Measures for each connected customer				
Offer in principle Queue Management (total) Incl. acceleration	Difference in time between actual connection date and counterfactual	Bespoke survey question on the	Quality of Connections Survey – bespoke Qs.	Report to Ofgem annually (RRP) and part of Close Out.

Scottish & Southern Electricity Networks TRANSMISSION

Incl minor modification Renew Product		counterfactual impact	Record as per survey timing.*	Enhanced Reporting Framework and Network for Net Zero Stakeholder Advisory Group.

*NOTE: this is **not** to form a satisfaction question as part of the ODI but input to the quantification of the CVP. By doing it alongside the QoC survey avoids survey fatigue

CVP 2B: Connecting for Society Above BAU in whole system network: Network Access Policy and CVP 2C: Connecting for Society Local and Community Energy

No, we strongly disagree with the proposals for CVP 2 and C and it remains our view that these proposals are **beyond business as usual** and drive significant consumer value as we have demonstrated using an evidence-based approach from RIIO-T1 experience.

We are concerned with the lack of feedback from Ofgem on our proposals. However, we have responded to Ofgem's feedback in its Draft Determinations for each of our CVPs following our Five Stage Approach to CVP in T2BP-DD-SHE-014 SHET Q4 Annex 2 of this question (see response to Core Q36). **Note we have included CVP 2B and CVP 2C in the above revised approach to CVP 2 to provide but a simplified methodology for the purposes of the CVP methodology**. As noted above, packaging the proposals will still deliver the same consumer benefits and policy outputs as outlined in our Business Plan.

CVP 6: Tackling climate change: Science Based Target to reduce GHG Scope 1 and 2 by 33%

No, we strongly disagree with Ofgem's draft decision to reject our CVP 6. **We believe that our ambition, track record and commitment to sustainability has not been recognised.**

We have responded to the feedback set out by Ofgem that there is no value to future consumers in setting an ambitious SBT. In response to Ofgem's feedback we have monetised the difference between the minimal requirements of a 2 degree SBT and our ambitious 1.5 degree target.

Stage 1 Minimum requirements+

SHE Transmission is the world's first electricity network company to set a 1.5 degree science based target. We are not waiting until RIIO-T2 to start action to reduce our own Green House Gas (GHG) emissions by 33%. **We are starting now and with the most ambitious scientific pathway. This follows being the first TO to commit to setting a SBT in May 2018.**

We note Ofgem's draft decision to reject our CVP on the basis that setting a SBT is a minimal requirement. The minimum Ofgem SBT expectation is a 2-degree target as noted during Ofgem - Transmission Owners Workshop on Draft Determinations on 27/07/2020. We have set a more ambitious target at 1.5 degree target. This will lead to a faster reduction of our GHG emissions that will benefit our environment, stakeholders and wider society as demonstrated below:

- 1.5 Degree: 33% reduction by 2025/26 and 46% reduction by 2030/31

- 2 degree: 8.61% reduction by 2025/26 and 14.76% reduction by 2030/31. Based on the Science Based Target initiative 2-degree pathway annual reduction threshold[79]

Overall, we believe our SBT has exceeded Ofgem's minimal requirements[80] by setting targets **almost four times that of the minimal requirements for RIIO-T2.**

Stage 2 Stakeholder support and consumer value

Our 1/3 reduction target for RIIO-T2 alongside our Sustainability Action Plan, which has resulted in setting our SBT, has been stakeholder led. Our stakeholders, including our shareholders, want us to take ambitious action on climate change and reduce our emissions following best practice in climate science through the SBT initiative. For further information see our sustainability action plan pages 8-10[81].

The value to consumers is realising the benefits of reduced carbon GHG emissions. A 1.5 degree target, as noted above, reduces this almost four times as fast. The benefits of investing in initiatives in RIIO-T2 to avoid emissions and make an absolute reduction will benefit consumers over the estimated 40 years of asset's life. This has a significant benefit to current and future consumers during and beyond the RIIO-T2 period.

Stage 3: Monetisation

To illustrate the benefit of setting an SBT we have set out a clear methodology:

- **Step 1:** Calculate the forecasted carbon avoided (tCO2e) against our 1.5 degree target from 2020/21 until the estimated end of asset design life (40 years)
- **Step 2:** Multiply the carbon by the carbon price (£/kgCO2e)
- **Step 3**: This equals a carbon value = consumer benefit
- **Step 4:** Estimate costs and benefits of a 2 degree target based on the carbon reductions that would be required by 2025 and 2030 under the SBTi guidance.
- **Step 5**: Calculate the difference between the consumer benefit of the 1.5 degree target against the 2 degree target
- **Step 6:** Deduct the costs associated with our RIIO-T2 initiatives
- **Step 7**: As our SBTi goes out to 2030 (10 years) we applied a 50% deduction, assuming only Net benefits during RIIO-T2 (5-year period)[82]

Analysis is attached in T2BP-DD-SHE-015 SHET Q4 Annex 3A and T2BP-DD-SHE-016 SHET Q4 Annex 3B.

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[79] www.sciencebasedtargets.org/wp-content/uploads/2019/04/target-validation-protocol.pdf

[80] **Ofgem** minimal requirements **Appendix 2:"*Business carbon footprint (BCF)* Adopt science-based target for company to reduce its scope 1 and 2 BCF by 20XX, without relying on international GHG offsetting**

[81] https://www.ssen-transmission.co.uk/media/3759/sustainability-action-plan.pdf

[82] This is an additional step following informal feedback from Ofgem from meeting with Anna Kulhavey dated 20 August 2020

SHET Q4 Table 4 - SBT CVP

	1.5 degree scenario	2 degree scenario	New Proposal (difference between the two)
Carbon Reduction	33% reduction by 2025/26 46% reduction by 2030/31	8.61% reduction by 2025/26 14.76% reduction by 2030/31	
Benefits	£32.9m	£12.2m	£20.7m
Costs	£23.69m	£8.78m	£14.91m
Net Benefit	£9.21m	£3.42m	£5.79m
50% RIIO-T2 assumption			c. £2.8m
CVP Benefit range			£2.8-5.8m

Assumptions:

- For each of the carbon reduction initiatives contributing towards our SBT, we have quantified the value of the avoided carbon emissions across appropriate time periods using the BEIS non-traded carbon price.
- Benefits from both scenarios are extrapolated out 40 years to reflect the GHG emissions avoidance that occurs over the asset design life.
- For emissions avoided as a result of IIG interventions these remain static while emissions avoided as a result of substation energy use interventions reduce in line with grid decarbonisation.
- Costs for the 1.5 degree scenario are actual as per the Business Plan submission while costs for the 2 degrees scenario are estimated based on the ratio between costs and benefits.
- A 50% reduction was applied to the Net Benefits to ensure this illustrates the RIIO-T2 period only. We believe this is a conservative assumption given the majority of interventions will take place in RIIO-T2 and not in the 2026-2030 period. And the costs of similar interventions in T3 would likely be lower due to efficiencies from T2.

It is important to note there in addition to the quantifiable benefits there are two qualitative consumer benefits:

- From our leadership. We have set the standard, leading the industry with an ambitious 1.5 degree target, raising the ambition of others including ahead of ED2. This is difficult to quantify and is not included in this benefit calculation.
- A requirement for **two-thirds of our supply chain** to set science-based targets. We have estimated this could add additional consumer benefit between £0.8m-£2.9m. This

illustrates our commitment to tackle scope three emissions illustrates both our leadership and going above

Although these benefits are difficult to quantify, **these should not be ignored and should be considered in Ofgem's final determinations** as explained in our response to core Q37. Including the above qualitative benefits this increases the range of consumer benefits range to £3.6m to £8.7m.

Stage 5: Return commitment

(NOTE: we move from Stage 3 to stage 5 as stage 4 refers to consideration of qualitative CVPs)
As outlined in our response to core Q36 and Q37, we're supportive of CVP clawback where targets are not met. We will report on our progress with our 1/3 reduction targets for RIIO-T2 to stakeholders and our new user group 'A Network for Net Zero Stakeholder Advisory Group'[83] with externally assured greenhouse gas (GHG) data reporting. The exact clawback mechanisms requires further engagement with Ofgem ahead of Final Determinations, should a CVP be rewarded.

SBT CVP outcome

Overall, we believe there is a significant consumer benefit from our ambitious world-leading SBT based on the 1.5 degree scenario. As outlined above this is estimated **at £9.21m** from the 1.5 degree scenario. We have been led by our stakeholder to set an ambitious target **beyond Ofgem and SBT initiatives minimal requirements**. As a result, we have estimated this will result in a range **£3.6m** to **£8.7m of consumer benefit (including both quantitative and more qualitative benefits[84]**). We believe this is a reasonable assumption when including the qualitative aspects of our CVP.

The policy intent of Ofgem's CVP was to reward ambition however **we do not believe this has been reflected in the Draft Determination outcome**. Specifically, we believe SHE Transmission to be ambitious relative to our network company peers in being the first company globally to set an SBT at an ambitious 1.5 degrees. The action and ambition of SHE-Transmission today will benefit consumers of today and **future consumers**. We believe the above proposal has responded to Ofgem's challenge in their Draft Determination and that there is demonstrable evidence-based consumer value.

[83] Details outlined in response to core Q1-5
84 £2.8m to £5.8m if you exclude more qualitative benefits

SHET Question 5: *Do you agree with our proposal to approve the Biodiversity No Net Loss / Net Gain CVP and do you agree with our proposal to re-quantify the value of it?*

We agree in part with the Ofgem's proposals on our CVP for Biodiversity.

We fully support the proposal to approve the CVP as it clearly goes above and beyond the minimum requirements set by Ofgem. In addition, we believe that rewarding our ambitious commitments that also go beyond regulatory and current industry practice is good for the environment and wider society, clearly demonstrated by the overwhelming stakeholder support. Our regional specific targets were co-created with stakeholders and are deemed as ambitious for the biodiversity challenges of our North of Scotland region.

However, we have strong concerns relating to any proposal that would look to re-quantify the value to the consumer away from our proposed approach, a willingness to pay study, for the following reasons:

Whilst there are a range of methods for assessing the value of biodiversity or natural capital, most of these do not provide a monetary valuation for biodiversity. Where they do provide monetary valuation, they are often partial, covering some services and not others. This is of concern as the methodologies we are currently aware of will not provide a comprehensive value for biodiversity (for which our proposed CVP is designed).

There is no commonly accepted industry standard for monetising biodiversity value for infrastructure projects. Indeed, we have made a commitment in our Business Plan to work with the wider sector in RIIO-T2 to help develop a Natural Capital methodology that is fit for purpose (see SHETL_SQ_POL_37). We are concerned that adopting a Natural Capital methodology prematurely, without rigorous stakeholder input and support, could be counterproductive in our ongoing efforts in creating a lasting best practice outcome.

Ofgem suggests that "[o]ther companies have quantified consumer value for similar activities for a significantly lower value that SHET's proposed CVP amount" (p21); however, it fails to provide any examples to support this statement and we have been unable to identify such comparators. In any event, each of the TO's have different commitments and ambition in relation to biodiversity and Natural Capital. Whist BNG and NC are often talked about interchangeably, they are distinctly separate proposals requiring separate calculation methodologies. We have reservations in trying to reach one consistent methodology between the 3 TO's, for different commitments, in an area where there are no industry accepted, off the shelf, methods that are appropriate.

To reaffirm the proposal for monetising this incentive through a willingness to pay (WTP) study in our Business Plan (Regulatory Framework - Outputs, Incentives, CVP & Innovation, December 2019), we note that WTP is an accepted regulatory tool that is used to ascribe a value to incentives (including the RIIO-T2 ENS incentive). Importantly, it is our firm view that the reward should be based on the CVP monetisation but not necessarily equal to the CVP monetised value. Whilst the WTP study, a study we undertook with the other GB TOS, valued our BNG commitments in the region of £160m, we are not asking for £160m in reward. We understand the WTP has limitations in the exact value consumers are willing to place on a particular area. However, what it does undoubtfully indicate is that this is an area that consumers think adds significant additional value. We would expect Ofgem to take a view on the quality, ambition and monetisation as a package to finalise the reward value for example making an estimation of the value based on £160m e.g. 10% of £160m = £16m.

We have further engaged with Ofgem to explore the above options[85] alongside others. We have also taken the initiative to engage directly with NGET TO to request using their Natural Capital tool. While we are interested in this tool, as noted above we feel that a Natural Capital based approach **may not be the most appropriate method for BNG** and are concerned that this could lead to undervaluing the consumer benefit for aspects that do not lend themselves to monetary valuation under currently accepted methodologies.

To date there has been limited direction and feedback from Ofgem on how best to approach valuing BNG consistency across TOs. Ofgem noted in its Draft Determinations "*We intend to engage with NGGT, NGET and SHET, who all submitted similar proposals in this area, to develop a robust common methodology for calculating the value that consumers place on biodiversity and natural capital ahead of RIIO-2 Final Determinations*[86]". Following Draft Determination publication, despite significant effort from SHE-Transmission, we have been unable to achieve that cross-party engagement due to the availability of others. We requested a cross-party workshop to discuss and debate options, however Ofgem were unable to arrange this until w/c 7 September 2020. Evidently this is not in time to agree a common position ahead of the Draft Determinations deadline of 4 September 2020.

We continue to engage with both Ofgem, and the other network companies affected to explore these options and welcome any feedback or commitment from Ofgem on the options we have proposed. As noted by Ofgem87 this engagement will go beyond the deadline for Draft Determinations and an appropriate methodology will be developed ahead of Final Determinations.

[85] The options discussed following meeting 13 August 2020 to develop a value for the CVP were:
NGET's natural capital tool
NGET's score card reward (based on a % of RIIO-T1 EDR)
Willingness to Pay – a % of consumer's WTP
A more qualitative approach – To be defined
[86] See section 2.80 https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_nget_annex_redacted_0.pdf
[87] Email dated 26 August 2020 from Jon Sharvill to Lauren Logan

SHET Question 6: *Do you agree with our proposed allowances in relation to load related capex? If not, please outline why?*

We do not agree with Ofgem's proposed allowances and outputs in relation to load related capex. Specifically:

SHET Q6 Table 1 – Summary of Draft Determination response – Load Related Capex

Draft Determination (DD)	Our Consultation Response
We disagree with the rejection of pre-construction funding (PCF) for 5 Large Strategic schemes. Pre-construction funding (PCF) is essential to ensure timely and efficient development, and ultimately, **timely and efficient delivery** of critical future schemes on our network. Both aspects are fundamental in ensuring we can meet the requirements necessary to achieve Net Zero – **building the right network, at the right time and the right price**.	We have updated our proposal for PCF in RIIO-T2 with further justification which demonstrates the clear need for advanced investment to will enable critical network developments. This is based on the latest background generation position and taking account of the latest NOA recommendation. **Ofgem should modify the Final Determination to reflect the clear need and justified expenditure. (Section 2 below).**
Section 3 We disagree with a number of proposals set out within the Draft Determinations (DD) relating to allowances spanning price controls.	**Ofgem should modify its Final Determination to reflect our proposals (Section 3 below).** This preserves the correct incentive properties for efficiency improvements and is consistent with previous regulatory decisions.
Section 4 We disagree with a number of proposals set out within the DD relating to Price Control Deliverables (PCDs)	**Ofgem should modify its Final Determination to reflect our proposals (Section 4 below). Ofgem should maintain an output based regulatory framework,** ensuring that it does not inappropriately create input targets and inhibit delivery of efficient customer outcomes. Ofgem already has the ability to take action in exceptional circumstances.
We disagree with a number of material aspects of the Cost Efficiency Assessment. This includes: • the benchmarking of lead and non-load allowances as modelled in the Project Assessment Model (PAM) • Ofgem's determination of project risk allowances • Ofgem's assessment of High and Low confidence data	In our response, we provided a detailed and evidence-based justification for each error and issue identified in the Draft Determination. • **Ofgem should provide an interim update on its updated assessment prior to the revised Open Hearings in October.** • **Ofgem should modify the Final Determinations as identified in each section.**

We have set out our detailed response for each of the sections within the DD below. Our response is structured as follows:

Section 1. Additional evidence provided to Ofgem
Section 2. Projects Spanning Price Control Period
Section 3. Price Control Deliverables (PCD)
Section 4. Cost assessment – adjustments to Unit Costs
Section 5. Cost assessment – adjustments to Risk allowances
Section 6. Cost assessment – High-Low confidence

Section 1. Review and comments on individual sections of Draft Determination

SHET Q6 Table 2 – Review of Draft Determination – Load Related Capex

DD para	Ofgem statement	SHE Transmission response
3.11	A summary table of SHE Transmission's LRE request is shown below.	The DD provides a detailed narrative and proposed allowance summary for costs associated within the RIIO-T2 period only. We have sought further clarity on treatment of costs incurred across price control periods, in particular the schemes with expenditure crossing both T1 & T2 periods. This is explained in more detail in the sections below.
3.11	A summary table of SHET's LRE request is shown below.	Table 14 – Ofgem appear to have categorised the Kinardochy scheme from Local enabling (entry) to wider works. This allocation is different to what we have presented within our BPDT and should therefore be changed for Final Determinations.
3.13 & 3.16	SHET's local infrastructure program comprises seven generation projects which commenced construction within RIIO-T1 but are currently forecast to incur expenditure in RIIO-T2 and deliver outputs (crossover schemes). The current RIIO-T1 licence allows the recovery of costs for schemes in-flight and that are expected to deliver in the first two years of RIIO-T2.	We agree with this statement but disagree with Ofgem's proposed allowances for volume driver crossover schemes, as set out in section 3.16 Table 15. The allowances proposed are based on SHE Transmission forecast spend for each scheme. This is an error as allowances for the infrastructure element of these schemes should be based on allowances using the RIIO-T1 Volume Driver recovery mechanism. See response for schemes that span price control periods in section 3 below for proposed treatment of volume driver crossover schemes.
3.25	We propose that the first two of these projects should be included in the baseline for RIIO-ET2 as they both anticipate delivering outputs within the RIIO-T2 period. The scope of each project is summarised in Table 17 below, along with the total requested RIIO-T2 allowance.	Our view is that Table 17 should also include our East Coast 400kV Incremental Upgrade scheme which delivers an output early in the RIIO-T3 period. We disagree with Ofgem's proposal not to approve full scheme costs and associated outputs as part of the RIIO-T2 determination, as outlined in section 3 below.
3.32	We conducted our own analysis to arrive at our view of efficient unit costs to the projects that have had their needs case accepted. This has resulted in a proposed unit cost efficiency reduction of £11m across the LRE projects.	The reduction referenced in this section refers to RIIO-T2 expenditure only. Our view is Ofgem should include reductions derived from the PAM model to reflect expenditure for schemes across the T1, T2 &T3 periods. Our response outlined in section 5 is drafted on this basis. The PAM highlights a reduction in Lead Assets of £0.4m relating to the Glenshero Connection Works. Since these costs are funded directly from the generator, we disagree these scheme costs should be assessed through Ofgem's PAM. It should be noted that the connection arrangement for this scheme has been modified meaning there is now a requirement to construct infrastructure assets for this scheme. This is a change from our BP submission and our proposal is

		the costs associated with the infrastructure assets will be recovered under the RIIO-T2 volume driver uncertainty mechanism. This change will be reflected in our updated BPDT submission.
3.38	We then divided the total project efficient cost for these projects to the following two parts according to the SHET's submitted profile. Our proposed funding approach is: First part up to and including 31 March 2021 of £72.4m will be funded in RIIO-ET1 subject to true-up; and Second part from 1 April 2021 to 31 March 2026 of £101.9 will be part of RIIO-ET2 baseline allowances with relevant PCDs.	We have been unable to reconcile the figures set out in this section - £72.4m & £101.9m. We think the figures have been derived by using a mix of schemes including and excluding indirect costs. We shared our working with Ofgem in an SQ w/c 31/8/20 (SHET-DD-CA-013).

Section 2. Additional evidence provided to Ofgem

2.1 Pre-construction funding

We strongly disagree with Ofgem's proposal to remove the pre-construction funding (PCF) associated with the following schemes from our baseline allowances for the RIIO-T2 period.

- East Coast 400kV Phase 2 Reinforcement;
- 2nd Eastern HVDC Link from SSET to England;
- Beauly to Denny 400kV (Uprating the 275kV cct for 400kV Operation);
- 2nd HVDC Link to SSET Shetland from Rothienorman; and,
- Skye/Western Isles Upgrade.

The total allowance associated with these schemes is £88.7m (Gross costs incl. £8.9m indirects).

Having access to adequate PCF is essential to ensure timely and efficient development, and ultimately, timely and efficient delivery of future schemes on our network; this is fundamental in ensuring we can meet the requirements to achieve Net Zero targets.

We have presented our views on Ofgem's proposals for (i) the definition of PCF and (ii) managing uncertainty in relation to pre-construction funding in our ET Annex Question ET Q11 & ET 12 responses and have presented our revised proposal for baseline PCF funding for Large Strategic Schemes based on the latest generation background and taking into account the latest NOA recommendations (Pre-construction funding Paper – T2BP-PAP-0016). We have also provided additional information for schemes that will require PCF funding in RIIO-T2 but won't be constructed until RIIO-T3 (T2BP-PAP-0017 PCF for T3 LRE Schemes)

- **Ofgem should reflect our revised PCF proposal and additional baseline funding of £124m in its Final Determination (£153m in total).**

2.2 Kinardochy

Ofgem has requested that we provide additional information to support the justification for inclusion of the Kinardochy scheme in our baseline allowance. We have prepared our paper ref T2BP-EJP-0023, which sets out the additional evidence to support the justification of the Kinardochy scheme. This paper confirms the following.

- The increased urgency of wider system background drivers for the scheme based on the latest energy scenarios.

- An update on the status of the contracted generation for which the scheme is enabling confirming that, in particular, Glenshero and Cloiche windfarms will connect before 2024 as expected (satisfying the condition noted by Ofgem in section 3.21 of its Draft Determinations).

- A combination of the preceding two points confirming the certainty and timing of the need with the delivery programme to demonstrate that for this scheme LOTI is inappropriate.

  - **Based on the updated information in this paper, we expect confirmation of the Kinardochy scheme in our baseline allowances in Ofgem's final determinations.**

Section 3. Projects Spanning price control periods

We disagree with several aspects relating to projects spanning price control periods that have been presented in Ofgem's Draft Determination, these are outlined below:

3.1 Volume Driver crossover schemes

Ofgem recognises that 'for seven of the nine generation connection projects spanning RIIO-T1/T2 the current RIIO-ET1 license contains a mechanism to derive the allowances for the whole span of these projects' (SHET Annex section 3.37).

Although we agree with this statement, we disagree with the allowances that have been proposed in the Draft Determinations for the seven volume driver schemes included within our Business Plan. The allowances proposed are based on the forecast expenditure for these schemes, not the allowances that would be triggered using the RIIO-T1 volume driver mechanism in line with our current license provision. This was flagged within our Business Plan submission and the current proposals are an error that needs to be resolved in Ofgem's Final Determinations. We have discussed this issue with Ofgem and highlighted through our SQ ref SHET-DD-CA-002.

Subsequent engagement (discussions and email confirmation), has clarified the following points:

- Agreement that for all volume driver crossover schemes (delivering outputs in the first two years of RIIO-T2), SHE Transmission will recover allowances based on the Unit Cost Allowances (UCA) from the RIIO-T1 Volume Driver recovery mechanism.
- Agreement that the allowances presented in the Draft Determinations for volume driver crossover schemes are based on our forecast expenditure and that this is an error and should be changed to reflect allowances triggered under the RIIO-T1 volume driver mechanism UCA.
- Recognition there will, and already has been, movement in the forecast outputs for our crossover schemes which means there must be flexibility in PCDs to adjust allowances to reflect changes due to generation scheme updates or delays in delivery programs.

We therefore propose to provide Ofgem with an update to allowances for crossover schemes (based on forecast output delivery and RIIO-T1 Volume Driver UCA) as part of the annual regulatory reporting submission and Annual Iteration Process (AIP) to reflect the latest output delivery forecast. This is in line with current reporting provisions within the RIIO-T1 license and will include a forward lookahead forecast to the end of year 2 in RIIO-T2.

We will also provide an update of our latest forecast for crossover schemes as part of a summary to reflect all changes since submission of our RIIO-T2 Business Plan, which we plan to submit to Ofgem at a later date. As part of this update, we will also provide an updated T1/T2 Crossover paper detailing the latest forecast expenditure and allowances for the crossover schemes.

- **Based on the above points, we expect the Final Determinations to set out allowances for our volume driver crossover schemes based on the RIIO-T1 volume driver mechanism UCA and recognise the need for an annual review of allowances to reflect the latest delivery forecast for these schemes.**

3.2 Advanced construction funding in RIIO-T1 for other schemes

Our Business Plan submission included projects for which £50.81m of advanced construction works (Gross incl. indirects) would be within the last year of the RIIO-T1 period. These are Tealing 275kV Busbar, North East 400kV Upgrade, East Coast 275kV Upgrade and Kinardochy Reactive Compensation (see Table 1, page 5 Supporting Narrative to Data Templates BPDT Narrative and each individual Project Cost and Efficiency Report for details). Our Business Plan proposal was based on these costs being recovered through additional allowances in the first year of the RIIO-T2 period on an NPV neutral basis. The expenditure forecast for these schemes has not been included or referenced in Ofgem's Draft Determinations, this is an error that needs to be resolved in Ofgem's Final Determinations.

We have discussed this issue with Ofgem and highlighted through our SQ ref SHET-DD-CA-002 and received confirmation via email this issue will be resolved as detailed within our Business Plan proposal. We will provide an update of the anticipated level of advanced construction spend as part of our update to reflect changes since submission of our Business Plan as mentioned above.

- **Based on the above points and any updated information that will be provided, we expect the Final Determination to set out allowances for advanced construction funding for schemes in line with the principles set out within our Business Plan submission (i.e. allowances included in first year of RIIO-T2 period on a NPV basis) and based on the latest forecast that will be provided in our updated BPDT submission.**

3.3 Funding proposals for schemes delivering outputs in RIIO-T3

Our Business Plan proposal included one scheme that spans the RIIO-T2/T3, the East Coast 400kV Incremental Upgrade. Ofgem has proposed a bridging fund to cover the allowances for this scheme with a true-up at the end of RIIO-T2. We disagree with this approach and propose the full scheme costs and associated outputs are approved in the RIIO-T2 determination. Our rationale for this approach is based on:

- Most of the expenditure on this scheme will be incurred in the RIIO-T2 period (>85%).
- We require certainty on the full scheme allowances to ensure we have financial certainty ahead of final investment decision on a project of this scale and complexity.

- Ofgem's proposal for true up of expenditure at the end of the RIIO-T2 period means the project costs won't be subject to TIM; this approach doesn't incentivise efficiency and is not in the interests of the consumer.
- Ofgem's proposed approach (section 3.33 Electricity Transmission Sector Annex) for dealing with schemes that cross the RIIO-T2/T3 boundary is based on asset intervention projects. The East Coast 400kV Incremental Upgrade scheme is a large Strategic load related scheme and such an approach is not proportionate for a scheme of this scale.

Based on the above points, the full scope and associated outputs for the East Coast 400kV Incremental Upgrade scheme must be approved within the Final Determinations

Section 4. Price Control Deliverables (PCD)

Ofgem has set output PCD proposals for both NOA recommended projects[88] and LRE projects[89]. Our views on both proposals are as follows:

4.1 NOA recommended projects

In relation to Ofgem's proposed PCD for both the East Coast 275kV Upgrade and North East 400kV reinforcements schemes our views are:

- In line with our comments above in section 3 relating to the assessment for the East Coast 400kV Incremental scheme, our view is this scheme must be assessed in full and a PCD deliverable (boundary capability uplift of 480MW) set in line with our Business Plan proposal.
- Ofgem has introduced a secondary deliverable for both the East Coast 275kV Upgrade and North East 400kV reinforcements schemes involving presenting the scope of works in the relevant EJP. We disagree with Ofgem's proposal for setting of these secondary deliverables in line with our response to SHET Q3.

Ofgem should set output based PCDs that are complete, comprehensive and remain aligned with output and incentive based regulation.

4.2 LRE projects

Our comments on these proposals are as follows:

1. Ofgem has merged the total output and costs for both infrastructure and TCA for each of the generation connection schemes within the table. This is an error.
    a. The output PCD deliverable should only relate to the infrastructure element of the scheme, in line with reporting in RIIO-T1 the TCA element (which is funded by the generator or DNO) should not have an assigned PCD. The TCA element should be treated separately as is the case in RIIO-T1 where it is subject to true up or logging up at the end of the price control through the close out process. We have recommended that the TCA true up on both allowances and revenue is done annually through the Annual Iteration Process (AIP) for RIIO-T2.

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[88] Ofgem, Consultation - RIIO-2 Draft Determinations – Scottish Hydro Electric Transmission, table 17

[89] Ofgem, Consultation - RIIO-2 Draft Determinations – Scottish Hydro Electric Transmission, table 19

   b. The allowances proposed for the volume driver crossover generation schemes are based on forecast expenditure and should be corrected to reflect allowances derived from the RIIO-T1 volume driver mechanism (see section 3 above).

2. In line with our comments in section 3 above, the table fails to reference the potential for generation volume driver scheme outputs to change because of changes in generator requirements. The table infers the allowances for the volume driver crossover schemes are fixed with no mechanism in place to adjust based on changes in delivery outputs (see section 3 above).

3. The allowances set out in table 19 are based on RIIO-T2 allowances only and therefore don't consider the costs for schemes with advanced construction costs in the RIIO-1 period (see section 3 above).

4. In line with point 1 above, the Glenshero windfarm scheme proposed in our Business Plan is based on a requirement for TCA only. A recent request by the developer for this scheme to change the connection point for this scheme means there is now a requirement to construct new infrastructure assets for the scheme. Our proposal is to recover the costs for this infrastructure under the RIIO-T2 volume driver mechanism. This will be reflected in our updated BPDTs submission.

All the above points must be addressed in the Final Determinations. Specifically, Ofgem must:

(i) **Present the costs and outputs for both the infrastructure and TCA elements for generation schemes separately;**

(ii) **Recognise that allowances for volume driver generation schemes may change depending on either generator requirements or program changes, with allowance being adjusted annually to reconcile with revised PCD outputs; and**

(iii) **Allowances and PCDs must also be presented to reflect provisions for schemes spanning multiple price control periods.**

<u>Cost Efficiency Assessment</u>

In this section we highlight material issues identified in Ofgem's cost assessment proposals. Each of these is explained in more detailed in the following sections. We provide the evidence to substantiate our statement and cross reference to relevant sections of our full consultation response.

SHET Q6 Table 3 – Summary of Totex allowance response – Issues impacting Load Related Capex

AREA	ISSUE	REMEDY - TOTEX
Unit cost efficiency	A combination of issues results in unit costs being unjustifiably cut, but most notably Ofgem do not account for project specific factors and assume T1 projects will be as per T2 projects.	Reinstate the unjustified unit cost cuts particularly around underground cable to the sum of £11m. (£14m based on assessment of T1 & T3 expenditure)
Risk	Ofgem's methodology states its allowed costs are based on RIIO-T1 outturn costs which include risk. Yet, in Ofgem's model over 77% of allowed costs are not based on outturn costs. Ofgem fails to account for other elements of risk including volume risk.	Reinstate risk costs of £31m, which Ofgem acknowledge as efficient. (£36m based on assessment of T1 & T3 expenditure)
Cost Confidence	Ofgem has not reflected the evidence provided in our project by project cost evidence when determining High-Low cost confidence categories. Furthermore, Ofgem has also incorrectly calculated the BPI and TIM sharing factor.	Reinstate the higher cost confidence evidenced in our plan and repeating in the summary provided to this consultation. Correct the identified calculation errors in the Plan incentives.

Section 5. Unit Cost Reductions

As part of Ofgem's cost assessment the DD has disallowed:

- £11m related to unit cost efficiency reductions (SHET Annex section 3.32) (£13.98m including crossover spend T1 & T3 for all submitted projects)

This reduction is the product of a number of issues, the main reductions are explained in the following sections.

- *SHE Transmission errors*: £4.7m - result of minor errors in our population of the volume and cost tables.
- *Specific Unit Cost reductions:* £2.8m – of cuts relating to higher unit rates which can be explained by either non-standard equipment or inclusion of scope elements which explain the variance against benchmark.
- *Underground Cable Unit Cost reductions*: £6.2m – of cuts to Underground Cable UC as a result of failure adjust for the material shift in average cable run lengths and location between RIIO-T1 and RIIO-T2.

5.1 SHE Transmission Errors

We have identified minor differences within our BPDTs that result in costs being assessed without a corresponding volume. The impact is that allowances are incorrectly reduced by £4.7 m. These are:

SHET Q6 Table 4 - Errors identified in BPDT

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Ofgem Value £m	Var. £m	Comment
SHT2000	TORI117 Tealing 275kV busbar	275kV Transformer	2.510	0	2.510	Misallocation of Cost – cost will be re-allocated to another category.
SHT2002	Kintore Substation Extension	275kV CB (Gas Insulated Busbars) (OD)	0.190	0	0.190	Cost Should be against 275kV Switchgear - Other Category
SHT2003	Rothienorman 400kv Upgrade	275kV Switchgear - Other	0.120	0	0.120	Costs Should be against 275kV VT Category
SHT2005	New Deer 400KV Upgrade	400kV OHL (Tower Line) Earth Wire	1.108	0	1.108	Should be a 400kV Switchgear - Other Category
SHT2005	New Deer 400KV Upgrade	400kV CT	0.813	0	0.813	Should be a 400kV VT - Other Category
		Total	4.739	0.000	4.739	

We have the full details of each of these allocation errors including specific details of where the costs should be reallocated in the BPDT for correction and costs re-instatement. This can be provided to Ofgem at any time ahead of Final Determinations.

5.2 Specific Unit Cost Challenges

We have through our analysis of the PAM, identified a further £2.8m of cost reductions due to our submitted Unit Cost values being higher than Ofgem's metric, on investigation, we have determined that there are very project specific reasons for each anomaly as outlined in the table below.

SHET Q6 Table 5 – Specific Unit Cost Challenges in Load Related Capex

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Ofgem Value £m	Var. £m	Comment
SHT2003	Rothienorman 400kv Upgrade	132kV Transformer	2.751	2.074	0.677	180MVA Rated Transformers (priced as a 275kV due to rating - bespoke equipment - no framework or historical cost)
SHT2009	East Coast 400kv OHL Upgrade	132kV CB (Air Insulated Busbars) (OD)	0.478	0.305	0.173	Cost higher due to allocation of proportion of shared costs with 400kV CB & 400kV Transformers
SHT20019	Glenshero Connection Works	132kV CB (Gas Insulated Busbars) (ID)	0.789	0.584	0.206	Cost includes GIB from incomer to GIS bay estimated at £222k (Switch Gear Other Cost?)
SHT20024	Moray West Offshore Windfarm	400kV CB (Gas Insulated Busbars) (ID)	4.264	2.515	1.749	High Rate due multiple assets included within the one asset in tables - cost includes the Gas Insulated Busbar as further Cost breakdown was not available at the time.

Total	8.282	5.477	2.805

We assume these instances will be evaluated and the costs re-instated. Should Ofgem require further details they can be provided.

5.3 Underground Cable Unit Cost reductions

The PAM has processed a reduction of £6.2m in our opening asset allowances across five schemes where the unit costs submitted for underground cabling (33kV, 132kV and 275kV) are deemed above the benchmark. We have reviewed these proposed cost reductions in detail and in line with our wider response on the UGC assessment (please refer to ETQ9 – UGC unit cost assessment), we strongly disagree with the unit cost reduction. We disagree with Ofgem's assessment based on the scope for our RIIO-T2 schemes being based on smaller, shorter runs within existing sites. The scope for each the T2 schemes is set out in Table 6 below followed by an overview of how this compares to our RIIO-T1 delivery program which was based on longer installations within agricultural land and the key factors that impact the unit costs assessment across the two periods.

SHET Q6 Table 6 – Underground cable atypical costs by project

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Volume km	Ofgem Value £m	Var. £m	Comment
SHT2003	Rothienorman 400kv Upgrade	33kV UG Cable (Non Pressurised)	0.415	0.5	0.158	0.257	Short Length in Existing Substation
SHT2004	Peterhead 400Kv Busbar	132kV UG Cable (Non Pressurised)	1.870	1.5	1.105	0.765	Multiple Short Lengths in Existing Substation – Tendered project, rate reflective of site conditions
SHT2004	Peterhead 400Kv Busbar	275kV UG Cable (Non Pressurised)	4.190	0.5	1.121	3.069	Short Length in Existing Substation – Tendered project, rate reflective of site conditions. 2500mm2 copper cable (more expensive than standard and heavier (more difficult to install). Various complicated crossings including a 70 bar gas line feeding Peterhead Power Station.
SHT2006	Alyth Substation	275kV UG Cable (Non Pressurised)	3.687	0.8	1.794	1.894	2nr Cable lengths (450m and 350m) connecting the Statcom and MSCDN - both cables are 400kV cable but being operated at 275kV initially (Hence allocated to 275kV UGC Asset category)
SHT20019	Glenshero Connection Works	132kV UG Cable (Non Pressurised)	0.381	0.25	0.184	0.197	Single Short Run connecting in to the existing adjacent Melgarve Substation

Total	10.543	3.5500	4.362	6.181

In our RIIO-T2 programme 77% of the projects have cable installations predominantly multiple short lengths within substations (either Existing or New Build). This is a fundamental shift in the average project scope in our RIIO-T1 cabling programme which was largely laying lengths in excess of 1km in open green field sites.

SHET Q6 Table 7 – SHET Cost Metric for 132kV Cable (Load & Non Load Projects)

132kV	RIIO-T1 SHET	RIIO-T1 SECTOR	RIIO-T2 SHET
Average length of cable / project	7.55km	9.35km	2.23km
Project cable runs	Limited runs / project		Multiple runs / project
Location	All in agricultural land		Substation (new / existing)

Our RIIO-T2 base cost metric of £1.320m per km for the laying of 132kv UGC has been derived from the outturn Unit Cost of 10 completed projects from the RIIO-T1 Period. The average length of the cable run in these 10 projects was 7.55km and 9 of the 10 projects were long runs in agricultural land. Only one project in the sample had multiple cables with single ends within the substation and this project had a unit rate of £2.8m/km. Even this project is not reflective of the complexity of installing full cable runs within an existing live substation.

Comparing RIIO-T1 and RIIO-T2 average 132kV project characteristics clearly demonstrates that the future programme of projects will entail work which will not be able to benefit from the economies of scale that were experienced during RIIO-T1.

- In particular, RIIO-T1 included work on the new Beauly Denny 400kV line. This included 35km of 132kV cable with associated low unit cost of installation, £0.57m / km
- In RIIO-T1 we completed 4 load projects in substations where cable data was captured. In RIIO-T2 we will complete 9 in substations.
- Our most expensive 132kV works in RIIO-T2 are on Lairg - Loch Buidhe scheme (SHT20018) - £4.93m/km. This is due to the 2 short circuits being installed in peat (therefore requiring significant ground stabilisation for the installation and to support the cable) and complex connection into the existing substation at Loch Buidhe. This project has been tendered and the submitted cost is reflective of the contractor having priced the specific project requirements.

SHET Q6 Table 8 – SHET Cost Metric for 275kV Cable (Load & Non Load Projects)

275kV	RIIO-T1 SHET	RIIO-T1 SECTOR	RIIO-T2 SHET
Average length of cable / project	3.45km	3.96km	2.34km
Project cable runs	single runs / project		1 project of 8 km (SHT2002 - Kintore Substation) – 4 other projects Multiple runs < 1km / project
Location	All in agricultural land		Substation (new / existing)

Our RIIO-T1 Cost Metric of £2.661m per km for the Laying of 275kv Underground Cable has been derived from derived from the Average Outturn unit rate of 3 projects identified with this asset category completed in the T1 Period. The average length of the cable run in these 3 projects was 3.45km and 2 of projects were single circuit cable runs in agricultural land.

In response to the Draft Determinations, we have conducted analysis on the 2 Weighted Average Unit Rates used by Ofgem to assess the 132kV UG Cable (non pressurised) and the 275kV UG Cable (non pressurised) as the table below.

Comparing RIIO-T1 and RIIO-T2 average 275kV project characteristics clearly demonstrates that the future programme of projects will entail work which will not be able to benefit from the economies of scale that were experienced during RIIO-T1.

- In particular, RIIO-T1 275kV work included no non-load asset replacement and in particular no substation replacements – all new assets were installed under wider works. The 275kV Cable laid under the Beauly Denny 400kV project joined the existing substation at Beauly to the new extension and therefore was only partially laid in an existing substation. The outturn unit cost for this installation was £4.64m / km.
- The benchmark RIIO-T1 rate is heavily informed by the large Sole Use project completed by SPT in 2017.
- In RIIO-T2 we have one very short length 275kV project – 500m at £8.38m/km – Peterhead 400kV Busbar (SHT2004). Due to the requiring a very high current to meet the transformer rating a 2500mm2 copper cable (more expensive than standard and heavier (more difficult to install) is necessary to meet 130% of the 1200MVA transformer. In addition to the added complication of installing a heavier cable, there are various complicated existing transmission crossings including a 70 bar high pressure gas line feeding Peterhead Power Station. These costs result in a disproportionately high unit cost when calculated over such a short length. We note NGET also undertook similar short lengths in RIIO-T1 with higher unit costs.

Further analysis of the available data RIIO-T1 points show there are no points <1km for 132kV and only 2 data points for 275kV UG Cable (Non Pressurised) less than 1 km available with an average (non weighted) unit cost of £17.302m / Km (below).

SHET Q6 Table 9 – Comparison of Ofgem benchmark data points

Under Ground Cable Sub-Category	Ofgem' Selected Metric	Total Volume in Sample (km)	Number of Data Points below 1 km	Avg UC £m/km (<1km)
33kV UG Cable (Non Pressurised)	User Overwrite Unit Cost - ED Ofgem Industry Incurred UC RIIO1* 1.2	?	?	?
132kV UG Cable (Non Pressurised)	T1 ET Sector: Weighted Mean	112.26	0	None
275kV UG Cable (Non Pressurised)	T1 ET Sector: Weighted Mean	27.711	2	17.302

Source: Ofgem Workbook: Unit_Costs_T1_Actuals_v1

We have also compared the average unit cost with some of the benchmark rates for underground linear assets in the GDN sector. The following table summarises the costs/km for the large diameter Repex activity (from available UC in T1 and T3). We use the larger diameter because in the lower diameters there are more options for mains insertion, directional drilling and network optimisation (abandoning without replacing). In the larger diameters the project scope change reflects the same sort of changes we are witnessing within the Transmission sector, namely: multiple connections per project, limited space / access, deep excavations, reliance on specialist labour, increased hand digging, lower labour productivity per metre, increased work within urban areas, etc.

We also note that the GDN unit costs are based on the average project length, therefore do not fully reveal the range in unit costs from very short lengths of replacement to longer runs. We also note the regional factor allowance Ofgem is proposing to reflect the higher costs of working in congested locations.

SHET Q6 Table 10 – Comparison of linear rates to GDN diversions – RIIO-T1 and RIIO-T2

GDN mains diversion works (£m/km)	RIIO-T1 London (Tier 1)	RIIO-T2 London (Tier 1)	RIIO-T1 Southern (Tier 3)	RIIO-T2 Southern (Tier 3)
Band e (250-355mm)	3.18	3.10	0.3	0.6
Band f (355-500mm)	5.57	6.51	3.83	9.33
Band g (500-630mm)	6.41	4.37	4.11	6.92
Band h (>630mm)	6.55	12.98	n/a	n/a

Source: Ofgem Cost Assessment excel file, published with consultation: riio_gd_model_suit_part_1[4] Diversions/ Cal_UnitCost_Submitted

As a result of the differences and divergence highlighted in the evidence above, we disagree with Ofgem's approach to assessing all project cable data using a single metric derived for that category without adjusting for the following factors:

- **Length of installation** (regardless of location) – The principle of economies of scale applies to linear cable installation – installing large volumes of something will cost less (per unit), installing very small volumes will cost much more (per unit). This is particularly pertinent to the installation of underground cable where you will incur large fixed cost that are not related to the length being installed. Examples of these are the cable sealing ends, contractor mobilisation to site, site set-up, cable purchase (minimum orders and penalties for short runs apply). On shorter lengths of cable these high fixed costs will not be spread over long installation lengths and therefore it will lead to a higher unit cost.
- **Costs arising from complexities of working within a live site** – Costs associated with working in a live substation environment cannot be assumed to be equivalent to installation through an open clear green field environment. These complexities particularly manifest themselves through the civils portion of the installation. Examples highlighted below:
  - Restricted access and constraints on working
  - Restrictions on Plant and Machinery usage and squad sizes
  - Excavating around existing assets often hand digging to locate services
  - Diversion of services and other cables (often offsite)

- Full trench sheeting over drag boxes and protecting open excavations from normal site operations activities
- Substation installations often require full concrete culverts & surrounds over their entire length for protection and maintenance
- Reinstatement works are often in roads and access points rather than grass
- High volume of large fixed cost like cable sealing ends
- Inefficiencies due to cutting and jointing multiple short lengths (often multiple cables per phase).

Recognising these issues, we included the flags for atypical costs within each relevant Project Cost and Efficiency Report (PCER) and then further within our responses to SHETL_SQ_ENG_2, SHETL_SQ_ENG_4, SHETL_SQ_ENG_7, SHETL_SQ_ENG_9 & SHETL_SQ_ENG_11. Although these SQs were specific to the Non Load Projects, the same principles outlined in the responses apply to the UGC on the load related schemes. We have committed to provide Ofgem with further substantiation to support our project costing and the principles outlined in the form of full project cost regression packs for 4 Non Load schemes selected by Ofgem (SHNLT2010 – Beauly, SHNLT2022 – Keith, SHNLT2021 – Kintore & SHNLT2023 - Willowdale) in the week following our Draft Determinations response.

Adjusting base prices to reflect project variation

In pricing the underground cable elements of the projects, we consistently utilised recent tender information. The principles below have been applied to ensure we reflect the different costs drivers and project specific factors that will impact unit rates:

- The cables are estimated and prices driven on a linear basis within 3 key parameters,
  - Out with Substation >1km
  - Within New Build Substation <1km
  - Within Existing Substation <1km
- The rates are to be considered "all in rates"
- All civils excavation and laying and reinstatement work is included in the rates
- All jointing, connections and cable sealing end compounds (and any civil work associated) is included in the rates
- The rates will take into account ground conditions with no further allowances or risks applied for this
- All service diversions / crossings, working around existing assets (hand digging and trench sheeting) and associated work involved are included in the rate.

The total of the above costs is represented in the relevant Voltage Cable Asset Category in accordance with our interpretation of the Transmission Glossary.

In summary, we have demonstrated the basis for a per project allowance for atypical costs arising from the length and location of the works. In particular, we have demonstrated that:

- while using historical and forecast unit costs is a valuable tool to establish benchmark costs, Ofgem's assumption that forecast underground cable assets can be benchmarked against RIIO-T1 metrics without adjusting for differences in project scope and scale is flawed;

- there is a material difference in the key cost drivers between the historical RIIO-T1 average sector unit costs and those which we will experience during RIIO-T2;
- have provided an accurate, consistent, market tested and real-world approach to the pricing of the Underground Cable Works (see our costing methodology and cost confidence section, below);
- comparisons can be drawn with other industries (data from RIIO-GD2) where it is accepted that there are potential significant cost increases per km as work moves to shorter lengths and more complex installation locations and ground conditions;
- the limited data points from RIIO-T1 do also demonstrate that high unit costs per project are experienced.

We believe the evidence demonstrates that all £6.2m of cable deductions should be reinstated.

5.4 General Use of Distribution Metrics as Benchmarks for Assessing Transmission Projects

As a general principle, we do not believe that use of distribution network cost metrics for 33kV, 11kV & 6kV assets is appropriate (even if a small multiplier has been applied). The scale and nature of Transmission projects is not comparable to the high-volume low-value model of the Distribution Businesses. Transmission projects will attract a significantly higher level of mark-up and shared project costs, the site durations will be far longer and will not tend to be in accessible locations like the bulk of Distribution projects. We will also not be able to achieve the buying gains on these assets that distribution will.

Section 6. Risk & Contingency Reductions

The Draft Determinations set out the costs that have been disallowed as part of the Costs Efficiency Assessment as:

- £31m related to reduction in risk and contingency (SHET Annex section 3.34) (£36m including expenditure spanning T1 & T3 periods)

The proposed allowances within the Draft Determination contain a number of errors and incorrect application of the evidence. We therefore do not agree with the proposed reduction in totex allowances. These can be summarised as follows:

1. Inconsistency between methodology and model.
   Methodology **-** Ofgem has stated that it will not apply our historical evidenced average risk uplift (8.2%) to asset costs (lead and non-lead assets). Its justification for this approach is within the Draft Determination annex:

   > *'This proposed level was based on a review of historical project delivery by SHET. However, as set out in the ET Annex, because the asset costs element of our view of efficient costs is based on outturn costs, we consider that it already accommodates any associated risk and contingency. Accordingly, we propose not to accept this 8.2% uplift for asset costs within the LRE and NLRE proposals. Furthermore, we propose to*

remove any risk elements for schemes where the phasing of key risks are outside the RIIO-T2 period.'[90]

Modelling – Ofgem's resulting totex allowance is in error because it does not apply the methodology set out above.

- 77% of our load asset costs within our RIIO-T2 BP have not been assessed using the T1 Weighted Average Unit Costs and therefore Ofgem's application of its proposed allowance cut is an error;
- Furthermore, Ofgem has capped allowances at our own forecast Unit Cost which is lower than the Ofgem RIIO-T1 Benchmark in 22% of the remaining 23% of assessed costs;

2. As per the methodology set out in the bullet point above, Ofgem has removed ALL Risk & Contingency allowances in the PAM from project SHT2004 – Peterhead 400kV Busbar, there has been no specific reasons given for this contradiction of the methodology outlined by Ofgem and accordingly, must have the allowances re-instated.
3. Our efficient risk rate has been based on over £2bn of projects. These include all elements e.g. preconstruction. Ofgem is incorrect to use a rate calculated on the full cost base to limited cost categories without also adjusting up the average risk rate.
4. Ofgem fails to account for any quantity-based risk on assets. This cannot be simply omitted from its modelling of forecast allowances.

We expand these points in the following sections.

6.1 SHET methodology and application – high confidence forecast of risk rate

For our Business Plan we assessed and applied risk based on a programme level analysis of 72 projects totalling £2.08bn. Risk and contingency costs can materialise throughout every stage of our project development process. The expected levels are refined as the project develops.

The analysis we conducted identifies the movement in total project costs once the project has been designed and tendered (Gate 3) until the point it is energised (Gate 5). This produced a Risk and Contingency uplift required of 8.2%. As our project costs are informed by recent tenders and project specific cost drivers, we consider the most appropriate RIIO-T2 risk estimate to apply is that which we have historically experienced between Gate 3 and 5 – 8.2% on all project costs.

In our submission we identified benefits / implications of using this methodology.

- Our calculated 8.2% is based on total costs Gate 3 to Gate 5 and therefore will **include volume risk** from changes in scope incurred during delivery.
- Our calculated 8.2% is a **net rate** – it includes the upward cost pressure of risk and contingency, but it also includes totex outperformance achieved during delivery. In our Plan we highlighted that applying the net rate on an ongoing basis embedded ongoing efficiency into our totex allowances. We estimated that this lies between £10m and £39m.

[90] Ofgem: Consultation - RIIO-2 Draft Determinations – Electricity Transmission Annex, §3.27 and Ofgem: Consultation - RIIO-2 Draft Determinations – Scottish Hydro Electric Transmission, §3.34

We illustrate this as follows:

	Illustration
Gate 3 estimated project costs £m (exc Quantified Risk Assesssment)	100
Gate 5 total outturn project costs £m	108.2
Average net risk rate experienced	**8.2%**
of which:	
Gate 5 total outturn project costs £m Without totex performance benefits	112
Totex outperformance delivered by Gate 5 £m	**-3.8**
Gross risk and contingency rate	**12.0%**
Gross Totex outperformance rate	**-3.8%**

- Our methodology is a **total project cost** approach. This is most appropriate to use based on a large sample of data and being applied to a large population of costs. It specifically reduces the potential modelling errors that arise when trying to identify and allocate risk outturn to individual activities, assets and causes.
- Application of the total project cost approach to individual cost areas in isolation is therefore inappropriate.

Therefore, we do not believe that the category-based approach to risk in projects is comparable to those submitted as part of the Business Plan. Any analysis done at the granularity Ofgem has attempted would be trying to be representative of projects that are far more developed than those within a Business Plan can be.

Our approach is valid and most accurate in determining an overall risk position for projects at a programme level and, as already highlighted to Ofgem. As highlighted by our external consultants Arcadis this rate is low as an overall inclusion on projects of this type at this stage of development.

The average RIIO-T1 risk rate of 8.2% must be applied without limitation to all forecast RIIO-T1 costs without deduction.

6.2 Inconsistency between methodology and model

Ofgem has provided additional background to the statements included within the ET and SHET Draft Determination Annexes.

a) R&C costs manifest themselves at the delivery stages of the respective TO's project stage gates;

b) The lead and non-lead assets costs across all TOs contain some element of R&C costs embedded because some risks have materialised and contingency costs w incurred while others have not. Therefore, the outturn asset unit cost themselves will have an element of this embedded are not exogenous to the R&C costs.[91]

[91] Transmission Risk and Contingency Costs Assessment, provided July 2020

Ofgem has used this principle to justify removing risk in its entirety from all lead and non-lead asset costs. We believe that Ofgem has not applied its own principle to our data and cost information correctly and consistently.

Ofgem's benchmark within the Project Assessment Model (PAM) is set using RIIO-T1 outturn unit rates for only 22.9% of assets by value (see Table 11). Furthermore, where our project unit cost submitted for an asset falls below Ofgem's benchmark unit cost our submitted RIIO-T2 unit rate has been used in lieu of the RIIO-T1 rate (see following table: Table 12). Therefore, the proportion of asset allowances with any connection to outturn rates is reduced further to 17.8% (22.9% * (1-22.01%)).

Therefore, the balance 82.2% of cost assessment is based on industry average forecast unit costs or individual company submitted unit costs. Forecast unit costs are totally free from risk and contingency impacts – they do not have "some element of R&C costs embedded" as is illustrated in the cost confidence information within our Project Cost and Efficiency Reports and expanded further in the following section. It is therefore wrong and inconsistent to have the same reductions applied to them.

Risk and contingency allowances must therefore be reinstated to all instances where RIIO-T1 rates have not in practice been applied.

SHET Q6 Table 11 – SHET Analysis of Ofgem PAM benchmarks by asset

LOAD PROJECTS	No.	Assets	Cost £m	% of Assets	% of Cost
TOTAL	99	6,116	403.547		
T1 ET Sector: Weighted Mean	19	362	92.319	5.9%	22.9%
T2 ET Sector: Weighted Mean	40	123	79.645	2.0%	19.7%
User Overwrite Unit Cost - EDOfgem Industry Incurred UC RIIO1* 1.2	2	1	0.988	0.0%	0.2%
User Overwrite Unit Cost - No Ofgem UC	38	5,631	230.595	92.1%	57.1%

SHET Q6 Table 12 – SHET Analysis of Ofgem PAM showing application of 'lower-of' benchmark or company unit cost

LOAD T1 Metric where Ofgem has Used SHET Base as Substitute to the Metric	Assets	Cost £m	% of Assets	% of Cost
T1 ET Sector: Weighted Mean	361.8	92.318		
SHET Base Rate used in lieu of T1 ET Sector	28	20.318	7.74%	22.01%
T1 ET Sector: Weighted Mean - Ofgem Rate Used	333.8	72.000	92.26%	77.99%

6.3 Risk and preconstruction – application of total cost risk rate to individual cost activities

The removal of risk from Preconstruction costs also does not follow the logic as laid out in Ofgem's narrative and therefore it is right to have a risk allowance applied. Ofgem has presented no evidence that removal of risk on the pre-construction element of or costs is justified.

The pre-construction phase of project development regularly experiences change to the scope of development and the requirements to progress the job. These are particularly prevalent once the consultation with major stakeholders, land owners and Local Authorities has commenced.

As an example, recently on LT000029 – North Argyll, we were required to conduct a subsea cable feasibility study following a routing consultation (Additional cost to development budget of £75k) and an underground cable feasibility study including identification of potential routes, GI works (including peat probing) and an in-depth contractor constructability study as an amendment to their Part A development Contract resulting in an additional £250k spend to the development phase.

The average preconstruction rate we have derived is based on total historical costs which must include the volume risk as described. We have established that volume risk could never be captured within the individual outturn unit costs. Therefore, to apply that total risk rate to individual cost elements with the exclusion of others is incorrect.

6.4 Volume / Quantity risk – equally valid risk and contingency driver not captured by unit costs

The removal of all risk on assets as per Ofgem's assertion refuses to acknowledge the presence of a volume or quantity risk on assets. This assumption is fundamentally flawed as it is irrefutable that asset quantities are equally subject to change through the design and development process.

Overhead lines and underground cables are particularly prevalent to this change. In the case of LT000040 – Inveraray to Port Ann Overhead line, Re-alignment & Re-routing took place due to all of the following factors:

- Presence of existing private hydro infrastructure following stakeholder engagement and surveys
- routeing following landowner engagement and surveys (Argyll Estates) changing the route at alignment stage due to issues raised regarding future forest management and the recognition of "specimen trees" which was supported by statutory authorities
- Underground cabling at Crinan Canal following consultation as OHL would be a visual impact at significant tourist visitor site
- Realignment following engagement and consultation with Forestry Commission

The risk is not exclusive to linear assets. Substation site layouts and specifications will change through the design of the site. Leading to change will directly have an effect on the costs associated with assets like the installation, commissioning and ancillary equipment.

Although an extreme example, through the detailed design phase of our Melgarve project, we were required to add a Static Var Compensator and all the associated switchgear and infrastructure associated with it.

Our 8.2% has been calculated to account for this volume based risk across our programme. In Ofgem's assessment, they have not supplied a workable and evidence-based alternative to our approach and therefore its conclusions are not justified.

Our forecast 8.2% risk and contingency uplift must be reinstated to asset categories as per the Business Plan Project allowances to account for volume based risk.

6.5 Risk & Contingency Summary

We have demonstrated that Ofgem has failed to apply its own methodology consistently or accurately and that its discounting of quantity risk in assets is flawed and unreasonable. We have demonstrated that our methodology is:

- Consistent with our Large Capital Works Process;
- Produces high confidence costs by using a large and evidenced source of data to benchmark risk rates (£2bn of RIIO-T1 outturn costs);
- Reflective and appropriate to the development stage of the projects;
- Evidence based, auditable and simple to apply; and,
- Leads to customer benefits by baking in historical levels of efficiency into the forecast and therefore under valuing the real underlying risk and contingency rate.

Ofgem has not supplied a workable and evidence-based alternative to our approach and therefore its conclusions are not justified.

Our forecast 8.2% risk and contingency uplift must be reinstated as per our Plan Project allowances.

Section 7. Higher and Lower Confidence Proportion in Baseline Totex Allowance

Although not specific to the Load Related Capex, we have included this section outlining our position to the level of cost confidence attributed to our Load project costs within our Business Plan submission. In supporting documents (T2BP-DD-SHE-005 SSEN Transmission - Totex Incentive Mechanism (TIM)) and (T2BP-DD-SHE-004 SSEN Transmission - Business Plan Incentive (BPI)) we have provided our complete response, outlining all arguments and presenting the evidence that support our conclusions.

We strongly disagree with Ofgem's view on the proportion of Low and High Confidence costs within our Baseline Totex Allowance. Based on the evidence above we believe that those projects removed by Ofgem should be reinstated, and classed as High Confidence, due to the uncertainty mechanism attached to this funding. This reinstatement will impact the proportion of Higher Confidence within our Baseline Allowances.

We also note that Ofgem has made errors or not considered all of the cost information in assessing cost confidence. Ofgem has:

- not fully considered a significant level of High Confidence costs submitted as part of our Project Cost & Efficiency Reports (PCERs) such as tendered costs;
- excluded specific projects from the BPI and TIM; and
- incorrectly classified certain categories as low confidence.

We provide detailed evidence of our approach and modelling in assessment the cost confidence of our baseline allowance, which support our conclusions, through our main consultation response and specific appendices[92]. Given the way Ofgem has applied the BPI and TIM assessment, both of these will be impacted by our proposed approach on cost confidence categorisation.

[92] T2BP-DD-SHE-005 SSEN Transmission - Totex Incentive Mechanism (TIM) and T2BP-DD-SHE-004 SSEN Transmission - Business Plan Incentive (BPI)

***SHET Question 7**: Do you agree with our proposed allowances in relation to non-load related capex? If not, please outline why.*

We do not agree with Ofgem's proposed allowances in relation to non-load related capex. Specifically:

We disagree with the rejection of 10 of our submitted 28 NRLE schemes. This conclusion is not supported by the investment evidence. We have committed to provide additional information through revised Engineering Justification Packs (EJP) to address all concerns raised by both Ofgem and Atkins in their respective reports. We expect this to result in the confirmation of our revised project proposals.

We disagree with the rejection of Preconstruction Funding for T3 NLRE and have provided additional evidence to support our justification.

We disagree with a number of very material aspects of the Cost Efficiency Assessment. This includes the lead and non-load allowances as modelled in the Project Assessment Model (PAM) and Ofgem's determination of project risk allowances.

We have set out our detailed response for each of the sections within the DD below. Our response is structured as follows:

Section 1. Review and comments on individual sections of Draft Determination

Section 2. Additional evidence provided to Ofgem

Section 3. Cost assessment – adjustments to Unit Costs

Section 4. Cost assessment – adjustments to Risk allowances

Section 5. Cost assessment – High-Low confidence

Section 1. Review and comments on individual sections of Draft Determination

SHET Q7 Table 1 – Summary of Draft Determination response – Non-Load Related Capex

DD para	Ofgem statement	SHE Transmission response
3.53	SHE T approach in "10 hydroelectric" stations of replacing associated equipment in advance of end-of-life on the basis that one intervention now is better than refurbishment now and replacement later. No comment is made on this yet the implication is that this is not acceptable.	As result the revised EJPs will make that specific comparison by means of a CBA to better demonstrate that this approach provides value for money. This is particularly the case where replacement is due in T3. The reference to10 hydro stations is an error; for the rejected schemes there are 11 transformers being considered at 7 separate sites, not all of which are exclusively hydro schemes. Sloy Substation is also a GSP supporting 627 Customers, only 138 of which are supported by backfeeds. Tummel Bridge is also a GSP and has a peak load demand of 12 MW for 6588 customers.
3.54	This paragraph comments on ACRs that do not clearly demonstrate the need for the replacement of high value assets	Consequently, an independent assessment has been made of the transformers to further inform the EJPs on the condition of the assets. Furthermore, where limited refurbishment options exist these will be explored as part of the CBA process.
3.56	This paragraph identifies proposed substation replacement works	This paragraph mistakenly adds the St Fillans project in this list when it is in fact a hydro scheme. For each of these projects further work has been undertaken to identify limited refurbishment options.
3.60	A cost efficiency reduction of £75m is proposed across the NLRE	Not accepted for the reasons outlined in this response.
3.61	A further reduction in risk and contingency of £25m	Not accepted for the reasons outlined in this response.
3.67	Ofgem proposes to classify £706m of the NLRE submission as low confidence, which is all projects bar Stornoway – Harris	We strongly disagree with Ofgem's view that SHET did not provide sufficient independent cost information to support high confidence classification for other costs within our NLRE submission. For each project, we submitted a detailed Cost Efficiency Paper which included a section on the costing approach and rationale for each project component. We believe that Ofgem has wrongly allocated a proportion of high confidence costs as low confidence and have overlooked the detail provide in the Cost Efficiency Papers. For example, we have provided for one particular scheme, SHNLT200 'Port Ann - Crossaig 132kV OHL Works', a CEP that showed £93.9m of project costs have been based on returned tenders. Ofgem define High Confidence costs as those which include 'Evidence that cost forecasts have been arrived at via a competitive process or other market testing'. We therefore believe that these costs should be considered as High Confidence in the BPI and TIM assessment. Moreover, we believe that this is just one example of where Ofgem has not completely considered the full suite of evidence we provided by SHE Transmission in relation to cost confidence and believe this should be addressed prior to Final Determinations.

3.68	As a result of Ofgem's proposal to disallow £244m as unjustified or inefficient costs. Ofgem has proposed a £24.4m disallowance penalty under the BPI stage 3 mechanism	A large proportion of this penalty is made up of the disallowed costs from the 10 schemes removed by Ofgem based on need and we believe that those projects which are rejected at the needs assessment stage do not progress to cost assessment. Therefore, these schemes could not be deemed inefficient or otherwise and subject to the BPI penalty, as the purpose of the BPI is to reward or penalise companies for "poorly justified cost forecasts". It is unreasonable to apply a penalty based on a difference of engineering opinion (that can be debated based on clear evidence), though we would nevertheless consider that the needs case we have presented is indisputable. The needs/engineering assessment does not suffer from information asymmetry in the same way as costs without appropriate benchmarks may. Each non-load project was the subject of its own detailed EJP, providing significant detail on each on which Ofgem could make a fully informed decision. While Ofgem may take a different view from the licensee, it does not follow that the licensee's view was unreasonable. The removal of allowances would be "penalty" enough but to overlay with a financial penalty is unreasonable and applying such a policy and penalising the full cost of those projects removed based on an engineering judgement is not promoting ambitious Business Plans. This is completely out of step with the RIIO-2 stakeholder-led approach – it punishes licensees for listening to stakeholders and responding to their expectations. This approach from Ofgem will negatively impact on future price controls. We also believe that Ofgem did not articulate the BPI policy clearly. At no point during the RIIO-2 process (be that through formal consultations or other Ofgem engagement) was it articulated that costs associated with the removal of schemes based on Ofgem's view of need would be subject to a penalty under the BPI. A small footnote in Ofgem updated the RIIO-2 Business Plan Guidance in 31 October 2019, which was not subject to consultation and a month prior to submission of final plans, stating that the stage 3 penalty could also apply to costs associated with activity volumes removed from the Business Plan by Ofgem does not articulate a policy shift. Also, through the bilateral engagement with the Ofgem Cost Assessment team it was communicated that only projects that reach costs assessment would be subject to the BPI.

Section 2. Additional evidence provided to Ofgem

Supplementary Questions Responses following submission of the Final Business Plan

The Table below shows the SQ responses we provided to Ofgem regarding the 10 NLRE schemes which Ofgem is proposing to reject in its Draft Determinations:

SHET Q7 Table 2 – Additional Evidence Provided to Ofgem

Project	SQ Number
Sloy Substation	SHETL_SQ_ENG _27
Culligran Substation	Nil
Deanie Substation	Nil
Quoich Tee Substation	Nil
Tummel Bridge Substation	Nil
Kilmorack and Aigas Substation	SHETL_SQ_ENG_44
Keith Substation	Nil
Broadford Substation	SHETL_SQ_ENG_61
St Fillans	Nil
St Fergus Mobil	Nil

From the table above, it is noted that Ofgem only raised 3 SQs following the submission of our Final Business Plan for the 10 rejected NLRE projects.

Ofgem and its consultants, Atkins, raised issues with the SHE Transmission's submission through Draft Determination process but given the paucity of engagement through SQs it would appear that insufficient effort was made by Ofgem to engage during the SQ process.

It is noted in the Atkins Summary Report[93] that the responses to SQs is part of the set criteria against which it assesses projects. If SQs have not been asked for a project that is subsequently excluded, then Atkins has failed in delivering on its own methodology and not taken advantage of the opportunity to further investigate the validity, or otherwise, of an EJP.

The extract below is from page 6 of the Atkins Report[94]:

> "Following initial review, Atkins raised Supplementary Questions (SQs) to receive relevant information. The formal SQ process was managed by Ofgem to seek clarification on any areas required. The SQ process was time limited and subject to resource constraints; where issues raised by SQs are outstanding these are noted in the assessment section for each of the TO's."

In this statement Atkins stated that:

- they would seek clarification on "any" areas required. This clearly has not happened.

[93] RIIO-T2 TO Submission Review Summary Report Rev2.0 | 2.0 | 18 June 2020
[94] Ibid page 6.

- The process was "time limited". This was an Ofgem process and if it was time limited for the consultants working on behalf of Ofgem then Ofgem is at fault for not making the time available for their consultants to do the appropriate level of investigation.
- The process was "subject to resource constraints". This statement provides little comfort to SHE T who has committed time and resources to a process that Ofgem itself has not fully committed to.
- Where issues were raised by an SQ that remain "outstanding" they are noted in the DD response. This would imply that the TO would get one chance to answer a question and no follow ups would be undertaken. This is not what was expected, is highly unsatisfactory and if further information was required then Atkins should have continued to engage; if any responses were insufficient the TO was to be advised, yet this did not happen for any of the SQs that were presented.

A summary of the changes made to the revised EJPs is provided below[95]:

- **Sloy Substation and GSP**: we retain our original ask of £45.3m. We have provided the additional justification through further analysis of our existing data by an independent transformer consultant. The options have been widened but will not include a refurbishment option as this is not appropriate for a family of transformers that have a potential common type defect which is contributing to their accelerated deterioration.
- **Deanie Substation**: we retain our original ask of £14.6m. We have provided the additional justification through further analysis of our existing data by an independent transformer consultant, who advises intervention in T2 due to an underlying thermal anomaly and contamination of the main tank oil. The CBA analysis includes additional options for T2 refurbishment followed by T3 and T4 replacement. However, the T2 off-line replacement solution still presents the best value for money.
- **Kilmorack and Aigas Substations**: we retain our original ask of £27.5m. We have provided the additional justification through further analysis of our existing data by an independent transformer consultant. The report includes the outputs from a recent environmental study which strengthens the need for action in T2. The CBA analysis include additional options for T2 refurbishment followed by T3 and T4 replacement. However, the T2 combined substation solution still presents the best value for money option.
- **Culigran Substation**: we retain our original ask of £14.3m. We have provided the additional justification through further analysis of our existing data by an independent transformer consultant. The consultant advises that intervention is required on this asset due to contamination of the main tank oil. The CBA analysis include additional options for T2 refurbishment followed by T3 and T4 replacement. However, the T2 off-line solution still presents the best value for money.
- **St Fillans Substation**: we retain our original ask of £6.8m. We have provided the additional justification through further analysis of our existing data by an independent transformer consultant. The consultant advises that intervention is required on this asset due to an underlying thermal anomaly. The report also includes the outputs from a recent environmental study which strengthens the need for action in T2. The CBA analysis includes an additional option for T2 refurbishment followed by T3 replacement. However, the T2 in-situ solution still presents the best value for money.

95 All costs referenced in this section are Gross including indirects

- **Tummel Bridge Substation and GSP**: we revise our original ask of £14.8m to £3.0m, accounting for a change of scope which now includes refurbishment. We have negated the need for load driven replacement through the implementation of an ANM solution.
- **Keith Substation:** we revise our original ask from £39.0m to £25.0m, accounting for a revised option to refurbish those elements needed to be replaced in T2. We have provided the additional justification and enhanced optioneering which provides an alternative value for money outcome. However, the poor operational configuration which was also one of the drivers for this project will not now be achieved with this revised solution.
- **Quoich Substation**: we retain our original ask of £13.6m. We have provided additional information on the condition of the breakers and investigated refurbishment of the assets. However, refurbishment is not a practical option and is ruled out in the analysis. The only valid option is off-line replacement.
- **Broadford Substation**: we revise our original ask of £1.0m to £2.5m. We have provided enhanced optioneering including 4 refurbishment options. The increase in cost is due to an increase in the options and the addition of diesel generation costs for running the Stornoway Power Station.
- **St Fergus Mobil and St Fergus Switching Station**: we retain our original ask of £12.7m. We have provided the additional justification for the protection upgrades and CB replacements at St Fergus Switching Station and enhanced optioneering including an in-situ refurbishment option. The replacement of the substation with an offline build coupled with the replacement of cables to the St Fergus Switching Station remains the best option to secure this site of national importance.

For both LRE & NLRE schemes, our forecast is based on current information that's available. These schemes will be subject to review and potential change depending on future condition reports and possible changes in background generation. **Our BP proposal recognised this uncertainty with a view the allowances for this spend will be subject to a 'symmetric true up at the end of the price control based on efficiently incurred expenditure'.**

In summary, of the £189.6m of NLRE projects that were rejected, revised documents have been prepared to provide additional justification that backs up our original request for funding.

Following discussions with Ofgem where they confirmed that funding for advanced Preconstruction works has been cut for schemes that will be constructed in the RIIO-T3 period, we have provided additional information to support the justification for Preconstruction Funding totalling £13m.[96]

Cost Efficiency Assessment

In this section we highlight material issues identified in Ofgem's cost assessment proposals. Each of these is explained in more detailed in the following sections. We provide the evidence to substantiate our statement and cross reference to relevant sections of our full consultation response.

[96] T2BP-PAP-0018 PCF for T3 NLRE Schemes

SHET Q7 Table 3 – Summary of Totex allowance response – Issues impacting Non Load Related Capex

AREA	ISSUE	REMEDY - TOTEX
Unit cost efficiency	A combination of issues results in unit costs being unjustifiably cut, but most notably Ofgem do not account for project specific factors and assume T1 projects will be as per T2 projects.	Reinstate the unjustified unit cost cuts particularly around underground cable to the sum of £75m.
Risk	Ofgem's methodology states its allowed costs are based on RIIO-T1 outturn costs which include risk. Yet, in Ofgem's model over 77% of allowed costs are not based on outturn costs. Ofgem fails to account for other elements of risk including volume risk.	Reinstate risk costs of £25m, which Ofgem acknowledge as efficient.
Cost Confidence	Ofgem has not reflected the evidence provided in our project by project cost evidence when determining High-Low cost confidence categories. Furthermore, Ofgem has also incorrectly calculated the BPI and TIM sharing factor.	Reinstate the higher cost confidence evidenced in our plan and repeating in the summary provided to this consultation. Correct the identified calculation errors in the Plan incentives.

The DD reductions in allowances relate to the projects that have had their needs case accepted by the Ofgem Engineering team. Ofgem has also rejected 10 non-load projects based on need (see preceding section of the answer to SHET Q7). Our response for reinstatement of allowances includes those reductions that would, in theory, be made to those 10 non-load projects excluded on the basis as calculated using the PAM. Our response is therefore based on the premise the DD is proposing a total reduction of £94.25m related to unit cost efficiency reductions and £35.5m reduction in risk and contingency. These have been derived from the Ofgem PAM model.

Section 3. Unit Cost Reductions

As part of Ofgem's cost assessment the DD has disallowed:

- £75m related to unit cost efficiency reductions (SHET Annex section 3.60) (£94.25 for all submitted projects)

This reduction is the product of a number of issues, which are then explained in the following sections.

- *SHE Transmission errors*: £5m - result of minor errors in our population of the volume and cost tables

- *Schemes with cost and no volumes*: £4.5m – where the Business Plan guidance leads to costs with no associated volumes on which to derive a benchmark allowance
- *Underground Cable Unit Cost reductions*: £76m – of cuts to Underground Cable UC as a result of failure adjust for the material shift in average cable run lengths and location between RIIO-T1 and RIIO-T2
- *Specific project Unit Cost challenges*: £8.1m – as a result of failure to adjust for identified project specific UC variances

3.1 SHE Transmission Errors

We have Identified minor differences within our Business Plan Data Tables that result in costs being assessed without a corresponding volume. The impact is that allowances are incorrectly reduced by £5m. These are:

SHET Q7 Table 4 - Errors identified in BPDT

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Ofgem Value £m	Var. £m	Comment
SHNLT2 00	Port Ann - Crossaig 132kV OHL Works	132kV OHL (Tower Line) Earth Wire	1.522	0.000	1.522	Volume allocated to 275kV Process
SHNLT2 00	Port Ann - Crossaig 132kV OHL Works	132kV Earth Wire Fittings	0.387	0.000	0.387	Volume allocated to 275kV Process
SHNLT2 04	Sloy Substation Works	132kV CB (Air Insulated Busbars) (OD)	0.181	0.000	0.181	Should be a 132kV Switchgear - Other Category
SHNLT2 04	Sloy Substation Works	33kV Switchgear - Other	0.121	0.000	0.121	Should be a 132kV Switchgear - Other Category
SHNLT2 07	Kilmorack Aigas Substation Works	132kV CB (Air Insulated Busbars) (OD)	0.623	0.000	0.623	Should be a 132kV Switchgear - Other Category
SHNLT2 010	Beauly Substation Works	275kV CB (Air Insulated Busbars) (OD)	2.284	1.535	0.749	No Cost or Volume added for the Switch Gear Other Category
SHNLT2 013	Quoich Tee Substation Works	132kV VT	0.257	0.000	0.257	Should be a 132kV CT Category
SHNLT2 016	Glenmoriston Substation Works	33kV UG Cable (Non Pressurised)	0.110	0.000	0.110	Should be a 6.6/11kV UG Cable Category
SHNLT2 017	Foyers Substation Works	275kV CB (Gas Insulated Busbars) (ID)	0.174	0.000	0.174	Should be a 275kV CB (Air Insulated Busbars) (OD) Category
SHNLT2 021	Kintore Substation Works	132kV CB (Air Insulated Busbars) (OD)	0.252	0.000	0.252	Should be a 132kV Switchgear - Other Category
SHNLT2 022	Keith Substation Works	132kV Transformer	0.136	0.000	0.136	Should be a 275kV Switchgear - Other Category
SHNLT2 024	Redmoss Substation Works	132kV Switchgear - Other	0.442	0.000	0.442	Volumes Missing
		Total	6.489	1.535	4.954	

Scottish & Southern Electricity Networks
TRANSMISSION

We have the full details of each of these allocation errors including specific details of where the costs should be reallocated in the BPDT for correction and costs re-instatement. This can be provided to Ofgem at any time ahead of Final Determinations.

3.2 Schemes with cost and no or non reflective volumes

We have Identified Schemes where the presence of costs with no corresponding volume within our Business Plan Data Tables leads to an unwarranted cut in allowances. This is not an issue with the cost assessment tool adopted by Ofgem (Unit Cost benchmarking) but a consequence of the limitations of fixed data table structures and the flexibility of the BPDT Guidance. In each of the instances listed below the costs are correctly coded to the asset category. However, the definition of asset addition in the Guidance precludes the inclusion of a volume against that spend in the tables.

- BPDT Guidance – C0.7 'General principle: Scheme Type will be driven by the primary purpose of the scheme and costs subsequently recorded against the primary activity/purpose chosen… When working on a range of assets, Scheme Type will follow the most substantive activity that defines the investment category used… We anticipate being able to query the type and extent of the intervention by asset within the "Investment Decision pack" prepared in support of the scheme.'

We raised this potential issue during the Plan development process but were unable to get clarity. Our submission therefore follows the Guidance as interpreted. The cost assessment model therefore identifies these as costs not justified by volumes and cuts the necessary allowance. The result is a reduction in asset of £4.491 m.

SHET Q7 Table 5 - Schemes with cost and no or non reflective volumes

Ref.	Project	Ofgem Asset Hierarchy Category	SHET value £m	Ofgem value £m	Variance £m	Comment
SHNLT205	Beauly / Aigas-Deanie 132kV OHL Works	132kV Tower	2.663	0.000	2.663	No New Assets - Cost is for Maintenance (New Arching Horns, Step Bolts, Painting etc.) on 92 Towers
SHNLT2011	Invergarry T 132kV OHL Works	132kV Tower	0.331	0.000	0.331	No New Assets - Cost is for Maintenance (New Arching Horns, Step Bolts, Painting etc.) on 11 Towers
SHNLT2014	St Fillans Substation Works	132kV OHL (Tower Line) Conductor	0.147	0.000	0.147	Cost is to Reconfigure existing 132kV Conductor into new substation location - No Asset volume being added
SHNLT2019	Tealing Substation Works	132kV Switchgear - Other	0.064	0.000	0.064	Volumes Missing – Surge Arrestors Only (not considered an Asset Count)
SHNLT2019	Tealing Substation Works	132kV Switchgear - Other	0.043	0.000	0.043	Volumes Missing – Surge Arrestors Only (not considered an Asset Count)
SHNLT2020	Peterhead Substation Works	132kV Switchgear - Other	0.503	0.000	0.503	Volumes Missing – Surge Arrestors Only (not considered an Asset Count)
SHNLT2022	Keith Substation Works	275kV Switchgear - Other	0.190	0.000	0.190	Cost for remedial work to existing 2 Bays
SHNLT2023	Willowdale Substation Works	132kV CB (Air Insulated Busbars) (OD)	0.478	0.000	0.478	Cost for remedial work to existing AIS Bays
SHNLT2027	Elmwood - Glenagnes Cable Works	132kV Tower	0.071	0.000	0.071	No New Assets - Cost is for Maintenance (New Arching Horns, Step Bolts, etc.) on 7 Towers

	Total	4.490	0.000	4.490

We continue to seek guidance on how these instances should be captured under the Volumes Tables in the BPDT and are willing to submit any updates as requested by Ofgem to reinstate the allowances.

3.3 Underground Cable Unit Cost reductions

The PAM has processed a reduction of £76.0m in our opening asset allowances across thirteen schemes where the unit costs submitted for underground cabling (33kV, 132kV and 275kV) are deemed above the benchmark. We have reviewed these proposed cost reductions in detail and in line with our wider response on the UGC assessment (please refer to ETQ9 – UGC unit cost assessment), we strongly disagree with the unit cost reduction. We disagree with Ofgem's assessment based on the scope for our RIIO-T2 schemes being based on smaller, shorter runs within existing sites. The scope for each the T2 schemes is set out in Table 6 below followed by an overview of how this compares to our RIIO-T1 delivery program which was based on longer installations within agricultural land and the key factors that impact the unit costs assessment across the two periods.

SHET Q7 Table 6 – Underground cable atypical costs by project

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Volume km	Ofgem Value £m	Var. £m	Comment
SHNLT207	Kilmorack Aigas Substation Works	132kV UG Cable (Non Pressurised)	3.034	2.0	1.473	1.561	Recent Tender Returns from the Killin Vista project (similar conditions although 3-4 km range) substantiates submitted rate
SHNLT209	Deanie Substation Works	132kV UG Cable (Non Pressurised)	1.517	1.0	0.737	0.780	Short Length in Existing Substation – Cable is being installed directly under the existing OHL due to space constraints and in existing Substation, excavation around existing equipment.
SHNLT2010	Beauly Substation Works	132kV UG Cable (Non Pressurised)	21.474	8.0	5.919	15.555	1 Long Run - 6km Base Rate 1.5m/km - Multiple Short Runs in Substation total = 2.035km @ £6m/km (SHETL_SQ_ENG_2)
SHNLT2015	Tummel Bridge Substation Works	132kV UG Cable (Non Pressurised)	2.343	0.4	0.295	2.048	6 Short Lengths (all under 100m) in existing Substation, excavation around existing equipment & complex existing cable crossings.
SHNLT2016	Glenmoriston Substation Works	132kV UG Cable (Non Pressurised)	0.588	0.1	0.074	0.514	1 Short Length (100m) in existing Substation, excavation around existing equipment & complex existing cable crossings
SHNLT2017	Foyers Substation Works	275kV UG Cable (Non Pressurised)	9.843	2.0	4.484	5.359	2 Lengths (1025m & 975m) in existing Substation carried out in each cable installed in separate stages. Excavation around existing equipment & complex existing cable crossings – Cost includes the removal of the existing oil filled cable on completion of 1st cable installation.

SHNLT2017	Foyers Substation Works	33kV UG Cable (Non Pressurised)	1.090	0.2	0.076	1.014	Cable runs along bank of adjacent Loch, mitigation and methods of working put in place to ensure no environmental incidents occur.
SHNLT2019	Tealing Substation Works	33kV UG Cable (Non Pressurised)	0.067	0.1	0.009	0.058	Single short length (100m) in existing Substation routed over the existing transformer bund and ducted between multicore cables and around existing equipment.
SHNLT2020	Peterhead Substation Works	132kV UG Cable (Non Pressurised)	2.743	0.5	0.331	2.412	2 Short Lengths (275m 225m) in Existing Substation, Excavation around existing transformer & complex existing cable crossings. (SHETL_SQ_ENG_9)
SHNLT2020	Peterhead Substation Works	275kV UG Cable (Non Pressurised)	6.096	0.4	0.897	5.199	2 Short Length (175m & 225m) in Existing Substation – rate includes the diversion of the 2 existing OHL circuits (including new towers) and installation into the existing building. (SHETL_SQ_ENG_9)
SHNLT2021	Kintore Substation Works	132kV UG Cable (Non Pressurised)	17.359	3.9	2.873	14.486	1 Run out with substation - 1.4km Base Rate 1.5m/km – 8 short runs (0.25 ave.) in existing Substation total = 2.035km @ 6m/km to include Offsite diversion of xpn, xps, xcn, xcs included in UGC section. 495 m of cable to be reinstalled during Stage 2 of Construction (volume not counted) including this volume would reduce SHET unit cost from £4.45m / km to £3.94m / km (SHETL_SQ_ENG_6)
SHNLT2022	Keith Substation Works	132kV UG Cable (Non Pressurised)	10.941	4.1	2.983	7.958	1 Run out with substation - 3km Base Rate 1.5m/km - Multiple Short Runs in Substation total = 1.050km @ 6m/km to include Offsite diversion UGC section (SHETL_SQ_ENG_4)
SHNLT2022	Keith Substation Works	33kV UG Cable (Non Pressurised)	0.807	1.0	0.316	0.491	Cable run in existing Substation, excavation around existing equipment & complex existing cable crossings.
SHNLT2023	Willowdale Substation Works	132kV UG Cable (Non Pressurised)	12.288	1.8	1.326	10.962	Multiple (7Nr) Short Lengths In Substation – cost also includes installation and removal of 600m of temporary 132kV Cable not included in asset volumes.

							Excavation around existing equipment & complex existing cable crossings. (SHETL_SQ_ENG_7)
SHNLT2023	Willowdale Substation Works	33kV UG Cable (Non Pressurised)	0.512	0.2	0.063	0.449	Very Short Length in Existing Substation. Excavation around existing equipment & complex existing cable crossings. (SHETL_SQ_ENG_7)
SHNLT2025	Redmoss - Clayhills Cable Works	132kV UG Cable (Non Pressurised)	10.166	9.6	7.072	3.094	Recent Tender Returns from the Killin Vista project (similar conditions although 3-4 km range) substantiates our submitted rate
SHNLT2027	Elmwood - Glenagnes Cable Works	132kV UG Cable (Non Pressurised)	8.484	6.0	4.420	4.064	Cable being installed in Road - High reinstatement costs and extensive traffic & public safety management
		Total	109.352	41.3	33.348	76.004	

In our RIIO-T2 programme 77% of the projects have cable installations predominantly multiple short lengths within substations (either Existing or New Build). This is a fundamental shift in the average project scope in our RIIO-T1 cabling programme which was largely laying lengths in excess of 1km in open green field sites.

SHET Q7 Table 7 – SHET Cost Metric for 132kV Cable (Load & Non Load Projects)

132kV	RIIO-T1 SHET	RIIO-T1 SECTOR	RIIO-T2 SHET (total project Lengths)
Average length of cable / project	7.55km	9.35km	2.23km
Project cable runs	Limited runs / project	Information not available	Multiple runs / project
Location	All in agricultural land	Information not available	Substation (new / existing)

Our RIIO-T2 base cost metric of £1.320m per km for the Laying of 132kv Underground Cable has been derived from the outturn unit costs of 10 completed projects from the RIIO-T1 Period. The average length of the Cable run in these 10 projects was 7.55km and 9 of the 10 projects were long runs in agricultural land. Only one project in the sample had multiple cables with single ends within the Substation and this project had a unit Rate of £2.8m. Even this project is not reflective of the complexity of installing full cable runs within an existing live Substation.

Comparing RIIO-T1 and RIIO-T2 average 132kV project characteristics clearly demonstrates that the future programme of projects will entail work which will not be able to benefit from the economies of scale that were experienced during RIIO-T1.

- In particular, RIIO-T1 included work on the new Beauly Denny 400kV line. This included 35km of 132kV cable with associated low unit cost of installation, [insert UC].

- In RIIO-T1 we completed 9 non load projects in substations of which 3 projects were only 132kV Transformer replacements. In RIIO-T2 we will complete 18 in substations.

- Our longest 132kV cable run non-load project in RIIO-T2 is Redmoss - Clayhills comprising 9.6km in two parallel circuits. We have costed this project using our recently tendered rate cost workbook. The forecast UC of £1.059m/km is only lower than our reference rates (£1.32m/km) as we are able to deploy an innovative solution to utilise existing steel carrier pipes

- Our most expensive 132kV works in RIIO-T2 are at the Willowdale substation - £6.8m/km. As highlighted within the EJP, our accompanying Project Cost and Efficiency Report and SQ response , the recommended option (supported by CBA output) was to rebuild on the existing live site. This therefore entails us to temporarily and then permanently re-route cable runs to facilitate the sequence of works. There is only 1.8km of 132kV works but this comprises multiple runs in proximity to the remaining live assets. As some of these works are the temporary re-routing of assets the temporary cable installed does not contribute to the new volume assets which we can include within the BPDT. This further inflates the assessed unit cost. The length of the temporary cable is approximately 600m (the cost of which will include the installation and subsequent removal), if this volume was added, it would drop the Unit Cost of the 132kV Cable to £5.1m/km. The permanently installed cable is made up of 7Nr lengths therefore an average of 0.26km per run.

SHET Q7 Table 8 – SHET Cost Metric for 275kV Cable (Load & Non Load Projects)

275kV	RIIO-T1 SHET	RIIO-T1 SECTOR	RIIO-T2 SHET (total project Lengths)
Average length of cable / project	3.45km	3.96km	2.34km
Project cable runs	single runs / project	Information not available	1 project of 8 km (SHT2002 - Kintore Substation) – 4 other projects Multiple runs < 1km / project
Location	All in agricultural land	Information not available	Substation (new / existing)

Our RIIO-T1 Cost Metric of £2.661m per km for the Laying of 275kv Underground Cable has been derived from the Average Outturn unit rate of 3 projects identified with this asset category completed in the T1 Period. The average length of the Cable run in these 3 projects was 3.45km and 2 of the projects were single circuit cable runs in agricultural land.

In response to the Draft Determination, we have conducted analysis on the 2 Weighted Average Unit Rates used by Ofgem to assess the 132kV UG Cable (non pressurised) and the 275kV UG Cable (non pressurised) as the table below.

Comparing RIIO-T1 and RIIO-T2 average 275kV project characteristics clearly demonstrates that the future programme of projects will entail work which will not be able to benefit from the economies of scale that were experienced during RIIO-T1.

- In particular, RIIO-T1 275kV work included no non-load asset replacement and in particular no substation replacements – all new assets were installed under wider works. The 275kV Cable laid under the Beauly Denny 400kV project joined the existing Substation at Beauly to the new extension and therefore was partially laid in an existing Substation. The Outturn Unit Cost for this installation was £4.64m / km.
- The benchmark RIIO-T1 rate is heavily informed by the large Sole Use project completed by SPT in 2017.
- In RIIO-T2 we have one very short length 275kV project – 400m at £15.24m/km - Peterhead Substation (SHNLT2020) . As noted in our Project Cost and Efficiency Report, this involves 2 short cable runs (175m & 225m), which due to the live and constrained existing substation requires cable runs to be in deep excavations and encased. This has led to complex cable crossings of 132kv cables to be delivered in an existing live substation environment. The cost also includes for the diversion of the 2 nr existing overhead line circuits at the substation (including demolishing and constructing 2 new towers) and for the connection of the cables into the existing building. These costs result in a disproportionately high Unit Cost when calculated over such a short length. We note NGET also undertook similar short lengths in RIIO-T1 with higher Unit Costs.

Further Analysis of the available data RIIO-T1 points show there no points <1km for 132kV and only 2 data points for 275kV UG Cable (Non Pressurised) less than 1 km available with an average (non weighted) Unit Cost of £17.302m / Km (below).

SHET Q7 Table 9 – Comparison of Ofgem benchmark data points

Under Ground Cable Subcategory	Ofgem' Selected Metric	Total Volume in Sample (km)	Number of Data Points below 1 km	Avg UC £m/km (<1km)
33kV UG Cable (Non Pressurised)	User Overwrite Unit Cost - ED Ofgem Industry Incurred UC RIIO1* 1.2	n/a	n/a	n/a
132kV UG Cable (Non Pressurised)	T1 ET Sector: Weighted Mean	112.26	0	None
275kV UG Cable (Non Pressurised)	T1 ET Sector: Weighted Mean	27.711	2	17.302

Source: Ofgem Workbook: Unit_Costs_T1_Actuals_v1

We have also compared the average unit cost with some of the benchmark rates for underground linear assets in the GDN sector. The following table summarises the costs/m for the large diameter Repex activity (from available UC in T1 and T3). We use the larger diameter as in the lower diameters there are more options for mains insertion, directional drilling and network optimisation (abandoning without replacing). In the larger diameters the project scope change reflects the same sort of changes we are witnessing within the Transmission sector, namely: multiple connections per project, limited space / access, deep excavations, reliance on specialist labour, increased hand digging, lower labour productivity per metre, increased work within urban areas.

We also note that the GDN unit costs are based on the average project length, therefore do not fully reveal the range in unit costs from very short lengths of replacement to longer runs. We also note the regional factor allowance Ofgem is proposing to reflect the higher costs of working in congested locations.

SHET Q7 Table 10 – Comparison of linear rates to GDN diversions – RIIO-T1 and RIIO-T2

GDN mains diversion works (£m/km)	RIIO-T1 London (Tier 1)	RIIO-T2 London (Tier 1)	RIIO-T1 Southern (Tier 3)	RIIO-T2 Southern (Tier 3)
Band e (250-355mm)	3.18	3.10	0.3	0.6
Band f (355-500mm)	5.57	6.51	3.83	9.33
Band g (500-630mm)	6.41	4.37	4.11	6.92
Band h (>630mm)	6.55	12.98	n/a	n/a

Source: Ofgem Cost Assessment excel file, published with consultation: riio_gd_model_suit_part_1[4] Diversions/ Cal_UnitCost_Submitted

As a result of the differences and divergence highlighted in the evidence above, we disagree with Ofgem's approach to assessing all project cable data using a single metric derived for that category without adjusting for the following factors:

- **Length of installation** (regardless of location) – The principle of economies of scale applies to linear cable installation – installing large volumes of something will cost less (per unit), installing very small volumes will cost much more (per unit). This is particularly pertinent to the installation of Underground cable where you will incur large fixed cost that are not related to the length being installed. Examples of these are the Cable sealing ends, Contractor mobilisation to site, site set-up, cable purchase (minimum orders and penalties for short runs apply). On shorter lengths of cable these high fixed costs will not be spread over long installation lengths and therefore it will lead to a higher Unit Cost.
- **Costs arising from complexities of working within a live site** – Costs associated with working in a live substation environment cannot be assumed to be equivalent to installation through an open clear green field environment. These complexities particularly manifest themselves through the civils portion of the installation. Examples highlighted below:
    - Restricted access and constraints on working
    - Restrictions on Plant and Machinery usage and squad sizes
    - Excavating around existing assets often hand digging to locate services
    - Diversion of services and other cables (often offsite)
    - Full trench sheeting over drag boxes and protecting open excavations from normal site operations activities.

- Substation installations often require full concrete culverts & surrounds over their entire length for protection and maintenance.
- Reinstatement works are often in roads and access points rather than grass
- High volume of large fixed cost like cable sealing ends
- Inefficiencies due to cutting and jointing multiple short lengths (often multiple cables per phase).

Recognising these issues, we included the flags for atypical costs within each relevant Project Cost and Efficiency Report and then further within our responses to SHETL_SQ_ENG_2, SHETL_SQ_ENG_4, SHETL_SQ_ENG_7, SHETL_SQ_ENG_9 & SHETL_SQ_ENG_11. We have committed to provide Ofgem with further substantiation to support our project costing and the principles outlined in the form of full project cost regression packs for 4 nr Non Load schemes selected by Ofgem (SHNLT2010 – Beauly, SHNLT2022 – Keith, SHNLT2021 – Kintore & SHNLT2023 - Willowdale) in the week following our Draft Determination response.

Adjusting base prices to reflect project variation

In pricing the Underground Cable elements of the projects, we consistently utilised recent tender information. The principles below have been applied to ensure we reflect the different costs drivers and project specific factors that will impact unit rates:

- The cables are estimated and prices driven on a linear basis within 3 key parameters,
    - Out with Substation >1km
    - Within New Build Substation <1km
    - Within Existing Substation <1km
- The rates are to be considered “all in rates”,
- All civils excavation and laying and reinstatement work is included in the rates,
- All jointing, connections and cable sealing end compounds (and any civil work associated) is included in the rates,
- The rates will take into account ground conditions with no further allowances or risks applied for this,
- All service diversions / crossings, installing temporary cables, working around existing assets (hand digging and trench sheeting) and associated work involved are included in the rate,

The total of the above costs is represented in the relevant Voltage Cable Asset Category in accordance with SHE Transmission’s interpretation of the Transmission Glossary

In summary, we have demonstrated the basis for a per project allowance for atypical costs arising from the length and location of the works. In particular, we have demonstrated that:

- While using historical and forecast unit costs is a valuable tool to establish benchmark costs, Ofgem’s assumption that forecast underground cable assets can be benchmarked against RIIO-T1 metrics without adjusting for differences in project scope and scale is flawed;
- We have demonstrated that there is a material difference in the key cost drivers between the historical RIIO-T1 average sector unit costs and those which we will experience during RIIO-T2;

- Our costing methodology and cost confidence section, below, also demonstrates how we have sought to provide an accurate, consistent, market tested and real-world approach to the pricing of the Underground Cable Works;
- Comparison with other industries (data from RIIO-GD2) demonstrates the potential significant cost increases per km as work moves to shorter lengths and more complex installation locations and ground conditions;
- That the limited data points from RIIO-T1 do also demonstrate that high UC per project are experienced.

We believe the evidence demonstrates that all £76m of cable deductions should be reinstated.

3.4 Specific project Unit Cost challenges

We have identified a further £8.082m of adjustments to the submitted asset values. On investigation, there are project specific reasons for each anomaly which we have summarised in the table below.

SHET Q7 Table 11 – Specific Unit Cost Challenges in Load Related Capex

Ref.	Project	Ofgem Asset Hierarchy Category	SHET Value £m	Ofgem Value £m	Variance £m	Comment
SHNLT200	Port Ann - Crossaig 132kV OHL Works	132kV CB (Air Insulated Busbars) (OD)	0.662	0.610	0.052	Project Specific Tendered Cost
SHNLT204	Sloy Substation Works	132kV Transformer	6.287	5.114	1.173	Extra over cost for Midel transformer due to noise concerns - Premium is £420k Per Transformer
SHNLT204	Sloy Substation Works	6.6/11kV CB (GM) Primary	0.731	0.126	0.605	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT207	Kilmorack Aigas Substation Works	6.6/11kV CB (GM) Primary	0.366	0.126	0.240	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT208	Culligran Substation Works	6.6/11kV CB (GM) Primary	0.176	0.063	0.113	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT209	Deanie Substation Works	6.6/11kV CB (GM) Primary	0.176	0.031	0.145	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT2014	St Fillans Substation Works	132kV Transformer	1.289	1.037	0.252	Extra over cost for Midel transformer due to noise concerns - Premium is £420k Per Transformer
SHNLT2014	St Fillans Substation Works	6.6/11kV CB (GM) Primary	0.177	0.031	0.146	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT2015	Tummel Bridge Substation Works	132kV CB (Air Insulated Busbars) (OD)	1.565	0.610	0.955	Miss allocation of Costs - Contains Civils & Switch Gear Other Costs

SHNLT2015	Tummel Bridge Substation Works	6.6/11kV CB (GM) Primary	0.205	0.063	0.142	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT2016	Glenmoriston Substation Works	6.6/11kV CB (GM) Primary	0.206	0.031	0.175	SHET Rate includes all ancillary 11kV equipment & Proportion of Other Assets Shared Costs
SHNLT2017	Foyers Substation Works	33kV CB (Air Insulated Busbars) (OD) (GM)	0.545	0.310	0.235	SHET Rate includes Proportion of Other Assets Shared Costs
SHNLT2017	Foyers Substation Works	33kV Switchgear - Other	0.464	0.111	0.353	SHET Rate includes Proportion of Other Assets Shared Costs
SHNLT2019	Tealing Substation Works	33kV CB (Air Insulated Busbars) (OD) (GM)	0.207	0.155	0.052	SHET Rate includes Proportion of Other Assets Shared Costs
SHNLT2023	Willowdale Substation Works	132kV CB (Gas Insulated Busbars) (ID)	6.571	6.419	0.152	Non SF6 Switchgear and therefore a premium on the asset cost - Includes GIB and all GIS Switch Gear
SHNLT2028	Harris - Stornoway 132kV OHL Works	132kV Pole	5.938	2.646	3.292	H Pole Construction along entire length, Remote Island Working & Transportation Costs, Current Market Timber Prices are not reflective of T1

Total	25.565	17.483	8.082

We believe there are robust reasons for each project variance. In particular we would highlight the following reasons:

5. **Harris-Stornoway (132kv OHL).** Within its Draft Determinations Ofgem states: '3.61 In reviewing our modelled cost outputs, we identified a systemic difference between SHET's proposed costs for a specific asset type, 132kV OHL (Pole Line) Conductor, for scheme SHNLT2028 Harris - Stornoway 132kV OHL Works, and our view of efficient unit costs for that asset. Following discussion with SHET, we accepted their rationale for the use of a higher unit cost for this project in our modelling. This change has been accounted for in our proposals below.'

   We recognise the supplementary question engagement that led to this confirmation. However, in the project assessment outcomes Ofgem has only applied the atypical costs to the conductor and missed the accompanying poles, reducing our 132 kV Pole allowance by the difference of our submitted rates to the sector benchmark. This is a clear disparity between the determination and the modelling.

6. We have proposed the use of Midel transformers to mitigate in locations where noise and visual mitigation is necessary due to planning and stakeholder feedback. In particular through the SQ process Ofgem asked us for further information on the costs of enhanced noise enclosure costs at Sloy Substation. This was provided through SHET_SQ_ENG_11 in January 2020. We have had no further enquiries from Ofgem on the information provided.

Furthermore, in SHET_SQ_CA_44, we also provided the sources of all our non-lead costing included within our plan for substations such as Sloy. This addressed the interaction of the requirement for Midel Transformers and a platform building.

The evidence and justification for the atypical costs to address noise issues in sensitive locations has been provided. Ofgem has failed to justify its rejection and therefore should reinstate all associated forecast costs.

We request that Ofgem address these individual instances in light of the information already provided and reinstate the costs. Should Ofgem require further details they can be provided.

3.5 General Use of Distribution Metrics as Benchmarks for Assessing Transmission Projects

As a general principle, we do not believe that use of distribution network cost metrics for 33kV, 11kV & 6kV assets is appropriate (even if a small multiplier has been applied). The scale and nature of Transmission projects is not comparable to the high-volume low-value model of the Distribution Businesses. Transmission projects will attract a significantly higher level of mark-up and shared project costs, the site durations will be far longer and will not tend to be in accessible locations like the bulk of Distribution projects. We will also not be able to achieve the buying gains on these assets that distribution will as we infrequently will be purchasing small volumes of switchgear and short cable lengths.

Section 4. Risk & Contingency Reductions

The Draft Determinations set out the costs that have been disallowed as part of the Costs Efficiency Assessment as:

> £25m related to reduction in risk and contingency (SHET Annex section 3.62) (£35.5 for all submitted projects).

The proposed allowances within the Draft Determinations contain a number of errors and incorrect application of the evidence. We therefore do not agree with the proposed reduction in totex allowances. These can be summarised as follows:

1. Inconsistency between methodology and model.

   Methodology - Ofgem has stated that it will not apply our historical evidenced average risk uplift (8.2%) to asset costs (lead and non-lead assets). Its justification for this approach is within the Draft Determination annex.

   'This proposed level was based on a review of historical project delivery by SHET. However, as set out in the ET Annex, because the asset costs element of our view of efficient costs is based on outturn costs, we consider that it already accommodates any associated risk and contingency. Accordingly, we propose not to accept this 8.2% uplift for asset costs within the LRE and NLRE proposals. Furthermore, we propose to remove any risk elements for schemes where the phasing of key risks are outside the RIIO-T2 period.'[97]

[97] SHET Annex RIIO-2 Draft Determinations July 2020

Modelling – Ofgem's resulting totex allowance is in error because it does not apply the methodology set out above.
- 44% of our non-load asset costs within our RIIO-T2 BP have not been assessed using the T1 Weighted Average Unit Costs and therefore Ofgem's application of their proposed allowance cut is an error;
- Furthermore, Ofgem has capped allowances at our own forecast Unit Cost which is lower than the Ofgem RIIO-T1 Benchmark in 31.5% of the remaining 56% of assessed costs;

2. Our efficient risk rate has been based on over £2bn of projects. These include all elements e.g. preconstruction. Ofgem is incorrect to use a rate calculated on the full cost base to limited cost categories without also adjusting up the average risk rate.
3. Ofgem fails to account for any quantity-based risk on assets. This cannot be simply omitted from its modelling of forecast allowances.

We expand these points in the following sections.

4.1 SHET methodology and application – high confidence forecast of risk rate

For our Business Plan we assessed and applied risk based on a programme level analysis of 72 projects totalling £2.08bn. Risk and contingency costs can materialise throughout every stage of our project development process. The expected levels are refined as the project develops.

The analysis we conducted identifies the movement in total project costs once the project has been designed and tendered (Gate 3) until the point it is energised (Gate 5). This produced a Risk and Contingency uplift required of 8.2%. As our project costs are informed by recent tenders and project specific cost drivers, we consider the most appropriate RIIO-T2 risk estimate to apply is that which we have historically experienced between Gate 3 and 5 – 8.2% on all project costs.

In our submission we identified benefits / implications of using this methodology.

- Our calculated 8.2% is based on total costs Gate 3 to Gate 5 and therefore will **include volume risk** from changes in scope incurred during delivery.
- Our calculated 8.2% is a **net rate** – it includes the upward cost pressure of risk and contingency, but it also includes totex outperformance achieved during delivery. In our Plan we highlighted that applying the net rate on an ongoing basis embedded ongoing efficiency into our totex allowances. We estimated that this lies between £10m and £39m.

We illustrate this as follows:

	Illustration
Gate 3 estimated project costs £m (exc Quantified Risk Assesssment)	100
Gate 5 total outturn project costs £m	108.2
Average net risk rate experienced	**8.2%**
of which:	
Gate 5 total outturn project costs £m Without totex performance benefits	112
Totex outperformance delivered by Gate 5 £m	**-3.8**
Gross risk and contingency rate	**12.0%**
Gross Totex outperformance rate	**-3.8%**

- Our methodology is a **total project cost** approach. This is most appropriate to use based on a large sample of data and being applied to a large population of costs. It specifically reduces the potential modelling errors that arise when trying to identify and allocate risk outturn to individual activities, assets and causes.

- Application of the total project cost approach to individual cost areas in isolation is therefore inappropriate.

Therefore, we do not believe that the category-based approach to risk in projects is comparable to those submitted as part of the Business Plan. Any analysis done at the granularity Ofgem has attempted would be trying to be representative of projects that are far more developed than those within a Business Plan can be.

Our approach is valid and most accurate in determining an overall risk position for projects at a programme level and, as already highlighted to Ofgem. As highlighted by our external consultants Arcadis this rate is low as an overall inclusion on projects of this type at this stage of development.

The average RIIO-T1 risk rate of 8.2% must be applied without limitation to all forecast RIIO-T1 costs without deduction.

4.2 Inconsistency between methodology and model

Ofgem has provided additional background to the statements included within the ET and SHET Draft Determination Annexes.

a) *R&C costs manifest themselves at the delivery stages of the respective TO's project stage gates;*
b) *The lead and non-lead assets costs across all TOs contain some element of R&C costs embedded because some risks have materialised and contingency costs w incurred while others have not. Therefore, the outturn asset unit cost themselves will have an element of this embedded are not exogenous to the R&C costs.*[98]

[98] Transmission Risk and Contingency Costs Assessment, provided July 2020

Ofgem has used this principle to justify removing risk in its entirety from all lead and non-lead asset costs. We believe that Ofgem has not applied its own principle to our data and cost information correctly and consistently.

Ofgem's benchmark within the Project Assessment Model (PAM) is set using RIIO-T1 outturn unit rates for only 55% of assets by value (see Table 12) Furthermore, where our project unit cost submitted for an asset falls below Ofgem's benchmark unit cost our submitted RIIO-T2 unit rate has been used in lieu of the RIIO-T1 rate ((see Table 13). Therefore, the proportion of asset allowances with any connection to outturn rates is reduced further to 37.6% (54.9% * (1-31.46%)).

Therefore, the balance 63.4% of cost assessment is based on industry average forecast unit costs or individual company submitted unit costs. Forecast unit costs are totally free from risk and contingency impacts – they do not have "some element of R&C costs embedded" as is illustrated in the cost confidence information within our Project Cost and Efficiency Reports and expanded further in the following section. It is therefore wrong and inconsistent to have the same reductions applied to them.

Risk and contingency allowances must therefore be reinstated to all instances where RIIO-T1 rates have not in practice been applied.

SHET Q7 Table 12 – SHET Analysis of Ofgem PAM benchmarks by asset

NON-LOAD PROJECTS	No.	Assets	Cost £m	% of Assets	% of Cost
TOTAL	396	4,109	353.608		
T1 ET Sector: Weighted Mean	19	805	194.019	19.6%	54.9%
T2 ET Sector: Weighted Mean	40	98	23.078	2.4%	6.5%
User Overwrite Unit Cost - ED Ofgem Industry Incurred UC RIIO1* 1.2	2	16	4.624	0.4%	1.3%
User Overwrite Unit Cost - No Ofgem UC	335	3,189	131.887	77.6%	37.3%

SHET Q7 Table 13 – SHET Analysis of Ofgem PAM showing application of 'lower-of' benchmark or company unit cost

NON-LOAD T1 Metric where Ofgem has Used SHET Base as Substitute to the Metric		Assets	Cost £m	% of Assets	% of Cost
T1 ET Sector: Weighted Mean		804.7	194.019		
SHET Base Rate used in lieu of T1 ET Sector		79	61.037	9.82%	31.46%
T1 ET Sector: Weighted Mean - Ofgem Rate Used		725.7	132.982	90.18%	68.54%

4.3 Risk and Preconstruction – application of total cost risk rate to individual cost activities

The removal of risk from Preconstruction costs also does not follow the logic as laid out in Ofgem's narrative and therefore it is right to have a risk allowance applied. Ofgem has presented no evidence that removal of Risk on the preconstruction element of or costs is justified.

The pre-construction phase of project development regularly experiences change to the scope of development and the requirements to progress the job. These are particularly prevalent once the consultation with major stakeholders, land owners and Local Authorities has commenced.

As an example, recently on LT000029 – North Argyll, we were required to conduct a subsea cable feasibility study following a routing consultation (Additional cost to development budget of £75k) and an Under Ground Cable feasibility study including identification of potential routes, GI works (including peat probing) and an in-depth contractor constructability study as an amendment to their Part A development Contract resulting in an additional £250k spend to the development phase.

The average preconstruction rate we have derived is based on total historical costs which must include the volume risk as described. We have established that volume risk could never be captured within the individual outturn unit costs. Therefore, to apply that total risk rate to individual cost elements with the exclusion of others is incorrect.

4.4 Volume / Quantity risk – equally valid risk and contingency driver not captured by unit costs

The removal of all risk on assets as per Ofgem's assertion refuses to acknowledge the presence of a volume or quantity risk on assets. This assumption is fundamentally flawed as it is irrefutable that asset quantities are equally subject to change through the design and development process.

Overhead Lines and Underground Cables are particularly prevalent to this change. In the case of LT000040 – Inveraray to Port Ann Overhead line, Re-alignment & Re-routing took place due to all of the following factors:

- Presence of existing private hydro infrastructure following stakeholder engagement and surveys
- routeing following landowner engagement and surveys (Argyll Estates) changing the route at alignment stage due to issues raised regarding future forest management and the recognition of "specimen trees" which was supported by statutory authorities
- Underground cabling at Crinan Canal following consultation as OHL would be a visual impact at significant tourist visitor site
- Realignment following engagement and consultation with Forestry Commission

The risk is not exclusive to linear assets, substation site layouts and specifications will change through the design of the site. Leading to change will directly have an effect on the costs associated with assets like the installation, commissioning and ancillary equipment.

Although an extreme example, through the detailed design phase of our Melgarve project, we were required to add a Static Var Compensator and all the associated switch gear and infrastructure associated with it.

Our 8.2% has been calculated to account for this volume based risk across our programme. In Ofgem's assessment, they have not supplied a workable and evidence-based alternative to our approach and therefore its conclusions are not justified.

Our forecast 8.2% risk and contingency uplift must be reinstated to asset categories as per the Business Plan Project allowances to account for volume based risk.

4.5 Our Risk & Contingency Summary

We have demonstrated that Ofgem has failed to apply its own methodology consistently or accurately. We have demonstrated that Ofgem's discounting of quantity risk in assets is flawed and unreasonable. We have demonstrated that our methodology is:

- Consistent with our Large Capital Works Process;
- Produces high confidence costs by using a large and evidenced source of data to benchmark risk rates (£2bn of RIIO-T1 outturn costs);
- Reflective and appropriate to the development stage of the projects;
- Evidence based, auditable and simple to apply; and,
- Leads to customer benefits by baking in historical levels of efficiency into the forecast and therefore under valuing the real underlying risk and contingency rate.

Ofgem has not supplied a workable and evidence-based alternative to our approach and therefore its conclusions are not justified.

Our forecast 8.2% risk and contingency uplift must be reinstated as per the Business Plan Project allowances.

Section 5. Higher and Lower Confidence Proportion in Baseline Totex Allowance

Although not specific to the Non-Load Related Capex, given the significance of the mechanism in RIIO-T2, we have included this section outlining our position the level of cost confidence attributed to our Non-Load project costs within our Business Plan submission. In supporting documents (T2BP-DD-SHE-005 SSEN Transmission - Totex Incentive Mechanism (TIM)) and (T2BP-DD-SHE-004 SSEN Transmission - Business Plan Incentive (BPI)) we have provided our complete response, outlining all arguments and presenting the evidence that support our conclusions.

We strongly disagree with Ofgem's view on the proportion of Low and High confidence costs within our Baseline Totex Allowance for Non-Load Related Capex. Based on the evidence above and provided through the submission of revised Engineering Justification Packs, those projects removed by Ofgem and deemed Low Confidence should be reinstated to our baseline. This reinstatement will impact the proportion of Higher Confidence within our Baseline Allowances.

We also note that Ofgem has made errors or not considered all of the cost information in assessing cost confidence. Ofgem has:

- not fully considered a significant level of High Confidence costs submitted as part of our Project Cost & Efficiency Reports (PCERs) such as tendered costs.

- incorrectly classified certain categories as low confidence where these categories meet Ofgem's High Confidence Criteria.

We provide detailed evidence of our approach and modelling in assessment the cost confidence of our baseline allowance, which support our conclusions, through our main consultation response and specific appendices. Given the way Ofgem has applied the BPI and TIM assessment, both of these will be impacted by our proposed approach on cost confidence categorisation.

***SHET Question 8:** Do you agree with our proposed allowances in relation to non- operational capex? If not, please outline why.*

We strongly disagree with the proposed allowances for Non Operational Capex, which has removed the allowances for our warehouses, control room plus a portion of IT expenditure. See below for a further response.

SHET Q8 Table 1

Non-operational Capex	Requested	Cut (need)	Cut (unit rates	Proposed
Warehousing	37.5	(37.5)	-	-
Climate Change	15.7	-	-	15.7
Operations Centre	15.0	(15.0)	-	-
Emergency Response & Cont. Planning	1.4	-	-	1.4
IT Projects	41.8	-	(5.1)	36.6
Tools & Equipment	1.0	-	-	1.0
OVERALL TOTAL	112.4	(52.5)	(5.1)	54.8

Warehouse expenditure

SHE Transmission does not agree with the proposed cut in allowances of £37.5m (net of capitalised indirect costs) in relation to our proposed warehouses. We submitted a strong case in our Business Plan with supporting evidence and have since obtained further evidence from external consultants over our existing facilities and the need to replace these. Further justification papers strengthening the need have already been submitted to Ofgem.

Following Draft Determination, SHE Transmission engaged Scala, an independent consultant to review the needs case for the warehousing proposal. They clearly show that the current facilities used by SHE Transmission are not suitable for the existing level of spares in storage, have some significant health and safety issues which cannot easily be rectified, and will not be able to cater for the additional level of spares expected to be stored as the network grows and diversifies over the RIIO-T2 period.

Scala clearly identify the need for new purpose built facilities to be developed over the RIIO-T2 period, which is fully justified and supported through a cost benefit analysis. Doing nothing is not a serious option and trying to build the warehouses over a longer period (i.e. straddling 2 price control periods) does not resolve fundamental issues such as health and safety, storage of existing spares in unsuitable conditions making them more likely to perish ahead of time and difficulty to access spares at key times of the year such as winter, where access is down several miles of single track rural roads which may not be gritted for several days.

A revised EJP has been submitted to Ofgem with the same requirements as the original paper. Costs have been revised down slightly (c10%) following independent cost benchmarking by Scala.

Operations Centre expenditure

SHE Transmission does not agree with the proposed cut in allowances of £15m (net of capitalised indirect costs) in relation to our proposed operations centre. SHE Transmission submitted a strong case in our Business Plan with supporting evidence. Further justification papers strengthening the need have already been submitted to Ofgem.

Following Ofgem's Draft Determination, the needs case for this proposal has been reviewed in collaboration with an independent consultant to provide further detailed analysis of control centre requirements in order to safely, securely and efficiently operate the network. There is clear evidence that for security of supply, improvements to site security for a site managing critical infrastructure is necessary. In addition, operating limitations of the current site highlight the need for significant improvements in operating tools and equipment to bring it line with similar network operators, as a minimum this will include large overview screens and network management tools. The independent review has further confirmed the need to be immune to extended loss of grid connection or other exceptional circumstances. Having considered the available options and the potential implications of each one, development of a new secure, purpose-built control centre was found to be the only acceptable outcome. In addition, the existing control room site at Perth would be refurbished to act as a contingency site in the event of the new control centre becoming unavailable e.g. due to fire. The recent corona virus pandemic has further strengthened the need to ensure contingency sites are available.

A revised EJP will be submitted with increased justification with costs remaining at circa £15m.

IT capital expenditure

SHE Transmission does not agree with Ofgem's proposed allowances in relation to Non-Op Capex IT Investment Plan (titled IT & Telecoms in the Draft Determination). However, we are pleased that Ofgem recognises the need for all the projects included in the IT Investment Plan.

We have been unable to calculate or identify where the proposed £5.1m cost reductions have been justified either through the Draft Determination, Consultants Report or ET Annex. Ofgem has advised that it is **NOT** providing its detailed "**assessment excel workbook tool**" and we therefore cannot confirm if this allowance deduction has been calculated correctly. We are working with both Ofgem and Atkins to resolve this and our right to respond is reserved pending receipt of further information from Ofgem.

SHE Transmission submitted a strong case in our Business Plan with supporting evidence which has been externally reviewed by Gartner Consulting as being within the expected range. Ofgem's own consultant "Atkins" who consider that the projects identified are ***"supported by a sound, verifiable bottom-up cost estimation facility, which means that cost estimates could be validated".*** Given this statement from Ofgem's consultant, the proposed cut is unjustified and should be reinstated.

Within the Draft Determination Section 3.75, it states:

*"**we consider that the associated costs lack robustness. In line with the process described in the ET Annex, we have made adjustments to proposed allowances. SHET requested a total of £41.7m for their IT&T projects of which we have allowed £36.6m**"*

Ofgem also state in Section 3.77 of the Draft Determination that:

"**all of non-operational capex costs are high confidence"**

The Atkins report also states:

*"**SHETL's projects are supported by a sound, verifiable bottom-up cost estimation facility**"*

It is therefore not clear to SHE Transmission on the reasons for the allowance cut. The £5.1m allowance cut from Ofgem differs from the Atkins report, but we have been advised this is an error in that report.

Within Atkins report para 6.3, it states:

"**Resourcing and cost estimates for all the named projects were provided in the "T2BP-EST-0014 IT Investment Plan (Non-Op Capex) Cost Estimate" workbook. It was not possible to align the costs in this file with those in the BPDT, but this is assumed to be due to data maturing as submission dates approached**"

SHE Transmission did not receive any questions with regard to the alignment of costs in T2BP-EST-0014 IT Investment Plan (Non-Op Capex) Cost Estimate and the BPDT. The costs outlined in T2BP-EST0014 IT Investment Plan (Non-Op Capex) Cost Estimate do align with the BPDT. We are working with Ofgem and Atkins to clarify and provide more information as required.

In addition to the above, SHE Transmission's IT expenditure has been assessed by external technology consultants (Gartner Consulting) who consider the investment plan to be within the expected range. It has been assessed as either following current industry trends or addressing existing shortfalls when compared to peers.

Other allowances

We welcome Ofgem's decision on all other areas of Non Op Capex.

***SHET Question 9**: Do you agree with our proposed allowances in relation to network operating costs? If not, please outline why.*

We strongly disagree with the proposed allowances for Network Operating Costs which is split between Capex Activities and Direct Opex, set out below:

SHET Q9 Table 1

Network Operating Costs	Requested	Cut (need)	Cut (unit rates	Proposed
Capital Activities				
Communications Upgrade	29.0	(29.0)	-	-
Protection Modernisation	21.0	-	-	21.0
Scada Replacement	6.2	-	-	6.2
Integrated Condition & Perf monitoring	43.4	(43.4)	-	-
HVDC computer refresh	3.3	-	-	3.3
Physical Site Security	8.8	-	-	8.8
Flooding	1.4	-	-	1.4
Persistent Organic Pollutants	6.7	-	-	6.7
Capital Activities - TOTAL	119.8	(72.4)	-	47.4
Direct Opex Activities				
Faults	4.7	-	(1.8)	2.9
Inspections	16.1	-	(7.0)	9.1
Repairs & Maintenance	51.8	-	(32.4)	19.4
Vegetation Management	9.8	-	(0.7)	9.1
Legal & Safety	5.6	-	(3.3)	2.3
Direct Opex Total	88.0	-	(45.2)	42.9
OVERALL TOTAL	207.8	(72.4)	(45.2)	90.2

Capital Activities – Communications Upgrade

We strongly disagree with Ofgem's decision at Draft Determination stage to deem the proposed communications upgrades project un necessary. Currently a high number of faults due to legacy wireless communications infrastructure leaves our network exposed, predominantly during periods of bad weather when we rely on our most critical services like protection and control the most and when our network is most vulnerable.

In addition to increasing reliability, the communications upgrades project has a number of already approved interdependencies that will not be fully realised should this project not go ahead.

We require an upgraded communications network to increase reliability of protection and control services, provide a black start voice service replacement due to removal of PSTN by BT, provide connectivity for cyber security products, provide connectivity to make STCP 27.01 possible and to provide bandwidth to enable the use of risk-based asset management technologies.

We believe that in general, the need for reliable communications services within an electricity network has not been properly assessed by Ofgem or their consultants so we have therefore re-submitted this paper in an aim to make this even clearer, further justifying the need and showing our detailed optioneering process. The overall scope and value of this project has reduced from £29m to £24.7m in an attempt to progress with a more incremental approach over more than one regulatory period.

Capital Activities – Integrated Condition & Performance monitoring

We do not agree with Ofgem's proposed cut of £43.4m for our Integrated Condition & Performance monitoring as we have submitted a strong case in our Business Plan with supporting evidence. Whilst the proposed works are justified and proportionate, in response to Ofgem's comments we have revised the scope and timescale of the proposed works. We intend to undertake the works over a longer period, straddling T2 and T3, and have revised the initial T2 scope to focus on the most urgent works that provide most consumer benefit, support the safe and secure operation of the transmission system and that will inform and help optimise asset replacement strategies over future price controls, with a focus on assets with T3 replacement timescales.

The proposed scope of work includes asset specific volumes identified for installation of transformer gas analysis, partial discharge monitoring, circuit breaker monitoring and overhead line dynamic line ratings using a robust risk benefit optioneering process in the case of substation assets, and a whole systems savings to the consumer-based process for overhead lines. Furthermore, the proposed works have been split into two separate papers – one for overhead lines and one for substation assets in order to provide clarity and to reflect the different approaches to detailed analysis and optioneering taken for the different technology types. These papers have also been designed to help deliver the 'five clear goals' that were developed through our stakeholder engagement process –helping deliver "100% transmission network reliability for homes and businesses", "£100 million in efficiency savings from innovation" and our target of "one third reduction in our greenhouse gas emissions".

Direct Opex Activities

We do not agree with Ofgem's proposal to cut £45.2m from our Direct Operating Activities covering Faults, Inspections, Repairs & Maintenance, Veg Management and Legal & Safety activities. This is a cut of 51% from our Business Plan submission with the largest cut relating to Repairs & Maintenance.

As part of our Business Plan submission we submitted a paper called "T2BP-EJP-0014 Operational Expenditure Justification Paper" which provided a well justified summary of our costs and need, which either seems to have been ignored or Ofgem has simply taken the results of their modelling for the Draft Determination publication. The T2 "Business Plan data tables" (BPDT's), in most area's for direct opex is now at a much more granular level for cost and volumes (i.e. all lead assets, voltages and with inspections and R&M now split) which were never reported in T1 and in some cases data not held and we advised Ofgem that due to this new data requirement there will be a certain level of cost splits and estimations within our submission and that the detailed unit costs should not be used when setting allowances.

Our T1 and current operating expenditure benchmarks as 100% efficient across European and GB peers under a rage of cost drivers which in forms our T2 cost base. Our T2 expenditure also benchmarks efficiently across our GB peers and on initial assessment appears to continue to benchmark at 100% efficient compared to European peers.

Ofgem has failed to take into account clear evidence for the RIIO-T2 cost arising from a tendered contract to maintain the new Caithness Moray HVDC which entered service in early 2019. The need for these costs were identified by Ofgem's consultants at the time that the original project need was assessed in 2014. The error arises because Ofgem's cost assessment models project forward historical costs (2013-2019) from a time period when the asset, and therefore costs, did not exist, meaning that they cannot account for the costs of the scheme in question.

Furthermore, Ofgem requested volume metrics to accompany the forecast costs for other Network Operating activities. Despite having received this data, Ofgem did not use them in the cost assessment process but rather asserts in the Draft Determination that we did not provide satisfactory evidence. We strongly disagree with this suggestion.

Instead of checking the logic of the modelling results and taking into account the comprehensive volume data that we provided, Ofgem has unreasonably proposed a cut to our allowances for Network Operations. This would leave us with a choice between maintaining the HVDC network or the AC system – but not both. These issues have resulted in an error of £45m (of which the HVDC facility accounts for £22m of this).

Ofgem has since re-worked its model using volume's provided as part of the original SQ process and we are still working with them on this but await the results. Our further right to respond is reserved pending receipt of further information from Ofgem. Its model simply takes the lowest T1 or T2 average cost, however within a growing network these T1 averages will naturally be lower. Our Network has grown in network size over the T1 period from c £1.2bn to £3.5bn and in T2 to circa £5bn. Averaging the costs make sense on a static network but not on one (such as ours) which is already considerably larger than 2013 and which will continue to grow in the T2 period and beyond. It also does not account for different types of plant and equipment and the cost of inspecting and maintaining these, including the need for specialist suppliers – e.g. HVDC, subsea cables, SVCs, etc.

Within our justification paper we set out the growth in assets from the start of T1 to the end of T2 but also split out a summary cost table from our current base in 2019. Ofgem has stated in its determination that we hadn't demonstrated our growth which we disagree with. This table specifically shows our business as usual expenditure and the larger one-off increases such as HVDC, subsea cable inspections and civils works. Within this Civils category, Ofgem again has used a naturally lower historical T1 rate, which is incorrect given the growth within our Network. No volumes are captured on civils. This is incorrect and Ofgem should assess these based upon our T2 ask.

In addition to this Ofgem has collected all Asset data from 2014 to 2026 which also clearly shows the growth in our Network.

If Ofgem fail to re-instate the requested allowances this means that SHE Transmission will be in the position of having to choose which plant and equipment it cannot inspect, maintain and repair – potentially failing to meet legislative requirements such as ESQC Regulations and significantly increasing the likelihood of power cuts, increased levels of environmental damage such as SF6 leakage and oil spillage, health and safety issues such as legionella, asbestos related incidents and increased fire hazards. The safety of staff and the public will also be put at risk due to cuts in inspection, maintenance and repairs allowances. Disallowing these costs contradicts specific targets set by Ofgem such as improvements in SF6 leakage reduction and Energy Not Supplied.

We will continue to work with Ofgem in an effort to reach a satisfactory outcome for both SHE T and consumers.

***SHET Question 10:** Do you agree with our proposed allowances in relation to indirect operational expenditure? If not, please outline why.*

We strongly disagree with the proposed allowances for Indirects. These are split into 2 categories, Business Support Costs (BSC) & Closely Associated Indirects (CAI).

Ofgem has proposed the following allowances:

- Business Support Costs £104.2m, a cut of £0.7m.
- Closely Associated Indirects £161.5m, a cut of £93.9m (37%)

Further analysis has been undertaken by our independent consultants, Oxera[99]. We rely on that report in full and do not seek to replicate it here. Its report and conclusions are provided with this response.

Business Support Costs

We support the allowance set by Ofgem of £104.2m for BSCs (a cut of only £0.7m relating to IT & Telecoms). Ofgem's model would appear to represent the relationship between our BSCs and capital expenditure. Therefore, it would be correct that the cost driver for Capex within Ofgem's modelling is not as prevalent in BSC as it is within CAIs.

Closely Associated Indirects

Ofgem has applied a cut of £93.9m which we strongly disagree with. We have highlighted fundamental modelling issues which cause us to conclude this is an error in the Draft Determinations. Initial discussions with Ofgem indicated a modelling error in its model which it has advised it will correct.

Double counting error within cost assessment model

Ofgem's CAI model contains a fundamental error. It deducts both a workload adjustment and Capping (outperformance) adjustment in error where only one is justified.

- Capping involves limiting allowances to the lower of Ofgem's benchmark or the company submitted forecast. Issues this this method are developed further by Oxera in its report[100]. In CAI, Ofgem has calculated the difference between its modelled costs (£297m) and our Business Plan submission (£245m)[101] as £58m. Its capping adjustment.

- Ofgem has also reduced our capex allowances following its engineering need review. Using its econometric model it estimated the value of this workload reduction, £84m. We also identified the CAI forecasts associated with the rejected engineering need, £25m.

We believe that Ofgem intended to adjust both the modelled and submitted CAI costs for the revised workload level and compare the workload adjusted CAI benchmark to company

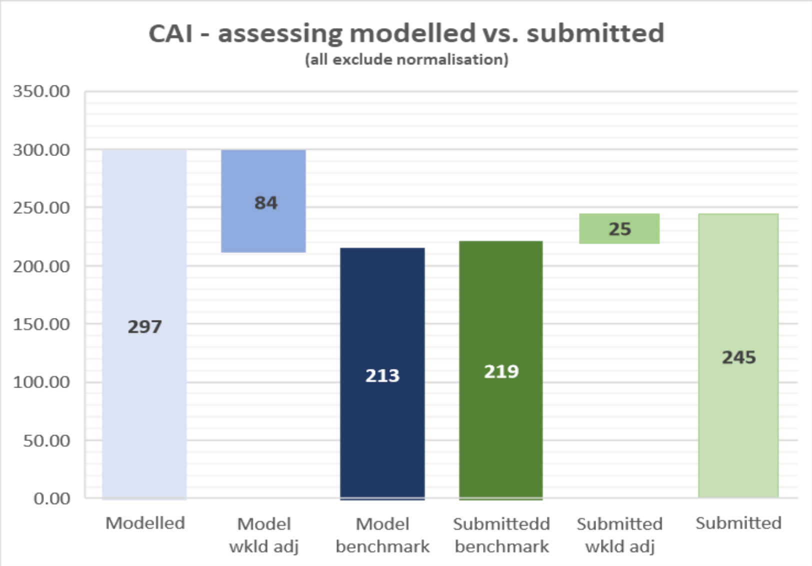
[99] Oxera: Ofgem's TOTEX assessment approach at the RIIO-ET2 draft determinations: a review, August 2020

[100] Oxera (September 2020), Ofgem's TOTEX assessment approach at the RIIO-ET2 Draft Determinations: a review.

[101] Both these CAI numbers are after separately assessed costs are removed, i.e. they are normalised costs.

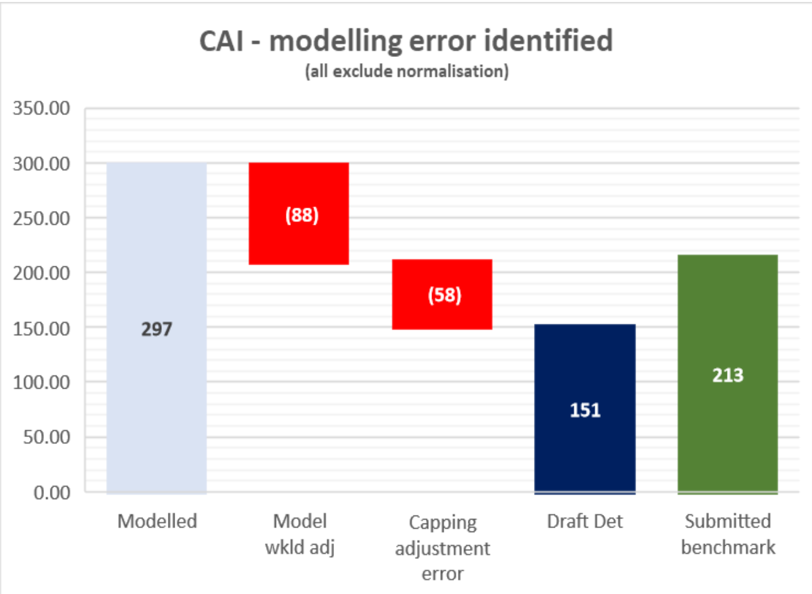
submitted equivalent. This is represented by the following graphic and results in the comparison of £213m and £219m.

SHET Q10 Figure 1 – comparing modelled and submitted workload adjusted CAI



However, Ofgem's modelling is flawed as it applies both a capping adjustment and workload adjustment resulting in a double count error. The error is created because Ofgem deducts the capping adjustment from the already efficient modelled and workload adjusted CAI costs. This is represented in the following graphic.

SHET Q10 Figure 2 – Ofgem modelled CAI showing 'double count' error



Initial discussions with Ofgem indicate there is a sequencing error in its model which we have been advised will be corrected. This leads to a double count error of c. £60-70m. Correcting for this should lead to the reversal of this deduction.

At a total CAI level our submitted costs represent materially better value for customers than the efficient costs produced by Ofgem's own economic modelling. Our Business Plan CAI forecasts also represent a comprehensive bottom up assessment of overheads required during RIIO-T2 and detailed breakdowns of the allocation of CAI overheads to capital projects. Given the model design points noted below, we believe that our Business Plan workload adjusted CAI costs should be accepted as efficient and more reliable than Ofgem's modelled outputs.

Therefore, our submitted capitalised overheads in relation to capital projects that have been cut for volume is only £25m. Ofgem should only deducted this portion from our Totex forecast, subject to any changes in the level Ofgem's engineering need assessment at Final Determinations.

Accounting for new and specific stakeholder requested expenditure

In addition to the above, the modelling performed by Ofgem does not cater for specific items included within our plan such as:

- Operation of the HVDC multi-terminal test environment, which during RIIO-T1 was funded under NIC. The cost of this is now with baseline opex as previously advised by Ofgem and this is included within our RIIO-T2 plan at c.£0.8m per year split between BSC and CAIs.

- Also included within our plan are new policy items which Ofgem has approved such as stakeholder engagement, sustainability and our environmental action plan (to name a few) and with this proposed cut we will not be able to deliver these.

- Additional operational training costs are also included due to our aging workforce and the need to bring in new recruits to replace them. Again, the modelling does not deal with this.

- These proposed cuts also impact our ability to implement certain policies which Ofgem has already approved, one of which is the Network Access Policy (NAP). The first and most important principle in the NAP (Special License Condition 2J) is maintaining a safe and reliable network. This is required to protect anyone in proximity to our assets and to ensure supply reliability. If our ability to maintain a safe and reliable network is compromised, then we are at risk of not being able to meet these license obligations. In all cases across GB, SHE Transmission has the best annual system availability, winter peak system availability along with the least loss of supply incidents (see NGESO published system performance reports). A lower resource as a result of incorrectly reduced allowances could create this operational tension.

Furthermore, as outlined in our Business Plan our CAI expenditure has already been benchmarked and found to be efficient by both CEER (Council of European Energy Regulators) and our own consultants Oxera. Both these reports should have led to Ofgem checking the illogical nature of its Draft Determination conclusion, i.e. that the most efficiency network, SHE Transmission, incurs a 37% cut in allowances.

General comment on econometric modelling

In Ofgem's independent consultant's report, our BSC and CAI costs are consistently identified as representing the industry efficient level. We note the range of models developed and tested. While we accept there is no perfect model, we believe Ofgem could identify a better balance of explanatory variables in place of those currently proposed.

We agree that capex and MEAV (the size of our network) are both appropriated cost drivers for CAI overheads. However, the model identified does not appear to pass the logic test as the coefficient weightings used favour capex over MEAV whereas only a proportion of our CAI costs are driven by capital projects.

MEAV (Modern Equivalent Asset Value)

Ofgem has decided to use MEAV as one of its cost drivers for the CAI modelling, however there was no guidance provided by Ofgem as to how this is to be calculated and each TO came up with their own methodology, which also raises concern around the potential inconsistency of data.

Final Determinations

We look forward to seeing revised models ahead of Final Determination which correct for these identified errors and issues and being provided the opportunity to review these.

For additional details of items included within our plan, the following document was submitted with our Business Plan "T2BP-EJP-0014 Operational Expenditure Justification Paper".

SHET Question 11: *Do you have any other comments on our proposed allowances for SHET?*

We have no further comments as we have provided a thorough and evidence based response above that justifies the 33% reduction to our base allowances being reinstated. However, we draw attention to the Main Response and in particular the following extract:

"Our Business Plan requires a lot from our organisation and others to deliver these targets. Therefore, we evaluated our delivery capability – would we be able to flex from the Certain View investment levels up to the range of higher investment required to achieve net zero pathways? We concluded that our base programme of £2.4bn is essential to ensuring we will have the supply chain capacity, the internal skills and resources and the infrastructure to deliver the investment required for net zero. The bigger the gap between the Certain View baseline and the net zero pathways then the more challenging that 'flexing up' becomes."

SHET Question 12: *Do you agree with our proposal to accept SHET's subsea cable repair re-opener?*

Yes, we agree. We support the window in January 2024 and another window at Close Out. As noted in our response to core Q12 and ET Q13, we no longer support 1% of annual base revenue as the trigger for any re-opener. This is on the basis that the RIIO-T2 price control presented at Draft Determinations is low return, high risk price and subsea cables faults are an area outside our control. In any case, a subsea cable fault would exceed the 1% but in principle we object to the materiality set for the aforementioned reasons and we would set the trigger, as we would for any individual re-opener at a reasonable cost for the regulatory burden (c£1m-£2m).

***Question 13**: Do you agree with the level of proposed NIA funding for SHET? If not, please outline why.*

Yes, we fully agree with the proposed NIA funding for SHE Transmission and we welcome that Ofgem has recognised that we have satisfactorily met three out of the four NIA criteria laid out in the Sector Specific Methodology Document and the Core Document. For the fourth criteria 'having processes in place to monitor, report and track innovation spending and the evidence that this is already happening', we understand your position and have the necessary measures in place, alongside the ENA, to ensure this is resolved in advance of our RIIO-T2 Final Determination.

As outlined in our Business Plan the NIA funding will allow us to respond to the challenges faced by our network in the transition to net-zero.

5 NARM Annex: consultation question responses

5.1 NARMs Introduction

Network Asset Risk Metric (NARM)

In general, we agree with overarching principle to introduce monetised risk targets as a primary output for Non-Load funding. We also agree that network companies must be held to account in delivery and output, equivalent to that it signed up to at the outset of the price control. A responsible network operator will always manage and maintain its assets appropriately, balancing an acceptable level of risk versus undertaking asset intervention and in line with its stakeholders' willingness to pay.

However, we are concerned that the long-term monetised risk output which has been proposed is:

Disproportionately Complex: The long-term monetised risk has been developed via limited attended working groups with no consultation process to get the views of wider stakeholders. There was limited guidance on how to complete the NARMs business tables, which left this open to interpretation which resulted in supplementary questions and further revisions following the submission of the Final Business Plan. The NARMs process, and the associated funding adjustment proposal, will require extensive granular reporting which will be burdensome for both network companies and Ofgem.

Immature and Not fit for Purpose: The current long term monetised risk output does not take into account nuances in networks across the UK, for example some of the Overhead Line schemes in the North of Scotland create significantly large monetised risk output due to areas of large customer demand and the lack of redundancy (network is radial in design – not meshed). This is clearly evident for SHE Transmission as one of our OHL schemes, Harris – Stornoway, which generates R£6,318.9m against Ofgem's proposed overall target of R£7,865.3m (80%).

Allowed Non-Load schemes has no Correlation to NARMS Target: SHE Transmission submitted 28 non-load related schemes which contains both lead and non-lead assets. As outlined above, we fundamentally disagree with Ofgem's Draft Determination to reject 10 of the 28 non-load schemes. It is the lead assets within these schemes which will make up our NARM target, however, the reduction in our NARMs target (R£2943.6m) made by Ofgem in its Draft Determinations does not correlate with the 10 rejected schemes (Total NARMS for 10 Schemes, R£44.4m) as we would have expected for the reasons explained below.

Ofgem NARMs output for SHE Transmission

SHE Transmission submitted a NARMs target of R£10,561.5m in its Final Business Plan, however Ofgem disallowed a number of volumes in its Draft Determinations following its assessment of the Network Companies' Business Plans, bringing down our NARMs target to R£7,865.3m. It is our understanding that all of the volumes disallowed in the Draft Determination have been disallowed in error by Ofgem. These volumes were disallowed on the basis of a rationalisation process between the costs and volumes (CV) submission and the NARMs submission. Where any discrepancies were found, volumes were rationalised based on the CV data. Whilst this may seem like a reasonable assumption on first inspection, the CV data does not include any refurbishment actions only additions, and disposals. The NARMs data however does account for both additions, and disposals as well as refurbishments. As a result, Ofgem has disallowed the volumes for all refurbishment interventions planned for T2 in its Draft Determination.

Taking this into account with the schemes which have been disallowed by Ofgem's engineering team based on its assessment of the need, it has resulted in flawed outcomes whereby we have an allowance which does not equate to the NARMs output which we need to deliver over the course of the T2 price control, this is represented in the tables below. Further detail is also provided in our response to NARMs SQ1.

NARMS Table 1: Proposed Schemes Rejected By Ofgem Based On Needs Assessment In Draft Determinations

PROJECTS	NARMS TARGET INCLUDED IN DDS?	COST ALLOWANCE INCLUDED IN DDS?	PROPOSED NARMs Value (R£m)
Sloy substation works (H)	Yes, NARMs output still included	No	11.7
Kilmorack Aigas Substation works (H)	Yes, Partial removal of Aigas s/s works, rest of the NARMs output is still included.	No	27.4
Culligran substation works (H)	Yes, NARMs output still included	No	19.8
Deanie substation works (H)	Yes, NARMs output still included	No	12.3
Quoich Tee substation works (H)	No, NARMs output removed due to -ve LTRB	No	-15.6
Tummel Bridge substation works (H)	Yes, NARMs output still included	No	10.6
Broadford substation works	No, NARMs output removed due to -ve LTRB	No	-26.1
St Fillans substation works	Yes, NARMs output still included	No	24.1
St Fergus Mobil substation works	Yes, partial NARMs output removed due to -ve LTRB	No	-42.2
Keith substation works	Yes, NARMs output still included	No	22.4

NARMS Table 2: Ofgem DDs NARMs Assessment

PROJECTS	NARMS TARGET	ALLOWANCE INCLUDED IN DDS?	NARMs Value REMOVED (R£m)
Port Ann/Crossaig (refurbishment)	No, refurbishment works removed	Yes	469.7
Sloy/Windyhill West (refurbishment)	No, refurbishment works removed	Yes	25.7
Invergarry T (refurbishment)	No, refurbishment works removed	Yes	0.1
Peterhead-Inverugie (refurbishment)	No, refurbishment works removed	Yes	476.0
Sloy/Windyhill East (refurbishment)	No, refurbishment works removed	Yes	16.7
Beauly/Aigas-Deanie (refurbishment)	No, refurbishment works removed	Yes	1.0
Redmoss (refurbishment)	No, refurbishment works removed	Yes	1.0
Harris/Stornoway (wood poles replacement)	No, wood poles replacement removed	Yes	1939.0
Aigas	Yes, Transformer and Under Ground Cable replacement included	No, removed as part of Ofgem's need assessment	14.4

We have submitted revised EJPs for all the schemes detailed in Table 1 above, providing additional justification and wider optioneering, and for some schemes we provided assessment and/or validation of need for proposed interventions by independent consultants. We believe this provides Ofgem with a clear need to undertake all of this work in the T2 price control and therefore the associated NARM output should be included within our target. In addition, we believe that the refurbishment works which have been disallowed from our NARMs target, outlined in Table 2 above, should also be included.

Ofgem's proposed funding adjustment – Unit cost of risk benefit

The application of the funding adjustment - i.e. utilising the final outturn unit cost of risk benefit value to determine the provided allowance works well in theory as the allowance given is always proportional to the benefits delivered (where the relationship between risk benefit and expenditure is linearised using the Business Plan values). However, in practice, this does not offer a viable method to determine the allowed expenditure for several reasons:

Mis-aligned to RIIO Framework: The funding adjustment proposal does not fit into the RIIO framework, one of the overarching principles of RIIO was to incentivise companies for justified overperformance and penalise companies for under performance. Therefore, the allowed expenditure should be locked at the Final Determinations stage and if a TO is not performing up to standard, or better than the standard, then penalties and incentives respectively should be provided to said TO. To be concise, the penalty itself should penalise TOs for poor performance, and there should not be a second penalty that modifies allowed expenditure. Furthermore, the proposed mechanism for RIIO-T2 does not help with additional issues found over the course of the

T2 period, as we have proposed to wider project works rather than interventions on one off items of plant it means that undertaking substitutions for unexpected failure of assets during the T2 period is extremely difficult. The T2 mechanism also means that we could potentially be penalized for justified over delivery.

Low Confidence and High Risk: A new methodology which is still to be validated or proven is being proposed to feed back into the allowed expenditure. This introduces significant risk to TOs and could also serve to introduce the distortions in TO operations that the proposed changes were designed to inhibit. For example, if the TO has unexpected but potentially justified additional expenditure on a planned scheme, the TO is now incentivised to try and trade for a more risk/cost beneficial scheme in order to make up the shortfall (to try and maintain proportionality between risk benefit and cost). In addition to this, the proposed methodology is not symmetrical for dealing with any over or under spend. The NARM methodology caps any benefits achieved by the network companies for under spend to 5%, however any overspend is entirely at the risk of the network companies. This means that there is no way to recover any overspend even if it is out with our control. We strongly recommend that Ofgem ensures that the mechanism is symmetrical for dealing with any over or under spend in undertaking Non-Load related works.

Promotes Inefficient Risk Aversion: Overall, contrary to Ofgem's statutory duties, the proposed funding adjustment principles does not act in the best interest of the consumer and encourages the TOs to take an overly risk averse approach. The potential change to the allowed expenditure based on final delivery encourages TOs to stick exactly to plan to minimise risk. The current mechanism actually encourages network companies to carry out its Business Plan, even if information comes to light which informs us that undertaking this work is not in the consumers interest. The mechanism means that we would only proceed with any interventions out-with the Business Plan when the assets have unexpectedly failed and therefore the justification for undertaking these works is undeniable. The proposed methodology therefore inhibits best practice of asset stewardship.

Further information on our position on Ofgem's DD NARMs decision can be found in our responses to SQ NARMQ1-Q4 below.

***NARMs Question 1:** Do you agree with our proposals on the scope of work within each of the NARM Funding Categories and on the associated funding arrangements?*

SHE Transmission broadly considers the proposals on the scope of work within each of the NARM Funding categories to be reasonable. However, there are various elements of Ofgem's analysis where SHE Transmission considers that Ofgem has taken an erroneous approach including as follows:

- The removal of NLRE schemes which generate a negative Long-Term Risk Benefit (LTRB)
- Reconciliation exercise between the Cost and Volumes tables and the NARMs Business Plan Data Tables
- Exclusion of Refurbishment works from the NARM target
- Exclusion of 132kV wood poles and Aigas scheme from the NARMs target
- We do not agree with Ofgem's removal of Long Term Risk Benefit (LTRB) as part of its Draft Determinations Proposal[102] and do not believe this is consistent with the scope of work defined in the document.

Removal of NLRE schemes which generate a negative LTRB

Ofgem has discounted all of our negative LTRB on the basis that if we were not to undertake the works then we would over-deliver against our NARM target. However, this means that if we were to undertake this work during the RIIO-T2 price control, then we will under deliver against our NARM target. Ofgem needs to recognise asset interventions resulting in a negative LTRB and incorporate this within its methodology in order to ensure that TOs (and other network companies) are not unfairly penalised for undertaking this work. Ofgem's removal of any negative LTRB from our NARM target in its Draft Determinations resulted in our NARMs target increasing from R£10,561.5m to R£10,808.9m.

Ofgem's reconciliation exercise between the Cost and Volumes tables and the NARMs Business Plan Data Tables

SHE Transmission considers that all of the volumes disallowed in the Draft Determination have been disallowed in error by Ofgem. To elaborate the volumes disallowed in the Draft Determination were disallowed on the basis of a reconciliation process between the costs and volumes (CV) submission and the NARMs submission. Where any discrepancies were found, volumes were rationalised based on the CV data.

Exclusion of Refurbishment works from the NARM target

Whilst this may seem like a reasonable assumption on first inspection, SHE Transmission's interpretation of the Ofgem guidance[103] is that the Cost and Volumes BPDTs does not include any refurbishment activities, only additions and disposals. The NARMs data however does account for both additions, and disposals as well as refurbishments. As a result, the volumes disallowed in the

[102] See table 1 of Ofgem's RIIO-2 Draft Determinations - NARM Annex published on 9 July 2020 https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_narm.pdf

[103] See Guidance for tables B4.5 / B4.5a (Scheme Asset Breakdown) and C2.5 / C2.5a (scheme Asset Breakdown) which can be found here: https://www.ofgem.gov.uk/publications-and-updates/riio-2-final-data-templates-and-associated-instructions-and-guidance

Draft Determination include all refurbishment interventions planned for T2. The table below highlights where Ofgem has unfairly disallowed refurbishment interventions from the NARMs target based on its reconciliation exercise between the CV data tables and the NARMs data tables.

NARMS Q1 Table 1

Scheme Location	Scheme Code	Asset Type	Intervention Type	Reason for removal
Port Ann/Crossaig	SHNLT200	132kV OHL Tower	Refurbishment	Replacement: 160 NARM, 160 CV Refurbishment: 23 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Sloy/Windyhill West	SHNLT201	132kV OHL Tower	Refurbishment	Replacement: 4 NARM, 4 CV Refurbishment: 47 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Invergarry T	SHNLT2011	132kV OHL Tower	Refurbishment	Replacement: 0 NARM, 0 CV Refurbishment: 11 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Peterhead-Inverugie	SHNLT2018	132kV OHL Tower	Refurbishment	Replacement: 0 NARM, 0 CV Refurbishment: 23 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Sloy/Windyhill East	SHNLT203	132kV OHL Tower	Refurbishment	Replacement: 4 NARM, 4 CV Refurbishment: 49 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Beauly/Aigas-Deanie	SHNLT205	132kV OHL Tower	Refurbishment	Replacement: 0 NARM, 0 CV Refurbishment: 93 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes
Redmoss	SHNLT2024	132kV Transformer	Refurbishment	Refurbishment: 2 NARM, 0 CV LTRB excluded from target due to no refurbishment volumes

Not having refurbishment actions included within the Business Plan for T2 would not be consistent with the license requirements placed upon SHE Transmission to act as a responsible TO acting in the best interest of the consumer. In order to maintain a safe and reliable network, asset companies can maintain, replace or refurbish its asset to reduce the likelihood and consequence of these assets failing. Therefore, it is essential that refurbishment work which can have a significant impact on the consequence or likelihood of assets failing is included in any asset management activities which we are funded to undertake, as outlined in paragraph 1.3 of Ofgem's Draft Determinations NARM Annex[104].

[104] https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_narm.pdf

Exclusion of 132kV wood poles and Aigas scheme from the NARMs target

Other removals outlined in the table below are assumed to be errors in the process of comparison with the cost and volumes spreadsheet and should be included within the T2 plan, for the reasons outlined below.

NARMS Q1 Table 2

Scheme Location	Scheme Code	Asset Type	Intervention Type	Reason for removal
Harris/Stornoway	SHNLT2028	132kV OHL Tower	Replacement	Replacement: 649 NARM, 0 CV Match failed as 649 wood poles do exist in the CV BPDT.
Aigas	SHNLT206	132kV Transformer	Replacement	The volumes for this scheme were included in SHNLT207 in the CV BPDT so match failed.
Aigas	SHNLT206	132kV Underground Cable	Replacement	The volumes for this scheme were included in SHNLT207 in the CV BPDT so match failed.

Ofgem has disallowed 132kV wood poles, stating that these are not "lead assets". We disagree with this view as SHE Transmission has always had 132kV wood poles included in the lead asset category for RIIO-T1, as outlined in our reporting throughout the RIIO-T1 price control and defined in the Electricity Transmission NOMs Methodology Issue 18[105] accepted by Ofgem, and Ofgem has suggested that wider asset categories should be developed and included in NARMs during T2 and beyond. Wood poles contribute towards over 25% of our total Overhead Line structures and therefore we recommend that these must be included within the lead assets category. Ofgem's disallowance of the LTRB for 132kV wood poles resulted in our NARMs target being reduced by R£1,939m.

Ofgem has not included the Aigas (SHNLT206) scheme output into our NARMs target, this scheme was combined with the Kilmorack scheme (SHNLT207). Therefore, our target should be increased by R£14.5m to include the output of Aigas and Kilmorack scheme within our target.

As stated at the outset of this response, we do not agree with Ofgem's removal of long term monetised risk (LTRB) as part of its Draft Determinations Proposal and do not believe this is consistent with the scope of work defined in the document. We have set out what we believe should be our NARMs target set out in the Final Determinations in the below table, this is based on our responses to the Ofgem SQs following the submission of our Final Business Plan, the information set out in this SQ response and taking into account some amendments to the scope of our Non-Load projects following the challenges on the Need by Ofgem's Engineering team and its consultants.

105 https://www.ofgem.gov.uk/system/files/docs/2018/08/noms_common_methodology_issue_18.pdf

Company Proposed (SHE-T)	Draft Determination Proposal (Ofgem)	Company Proposed (Including re-worked schemes) (SHE-T)
R£10,561.5m	R£7,865.3m	R£10,887.6m*

*best estimate based on revised EJPs.

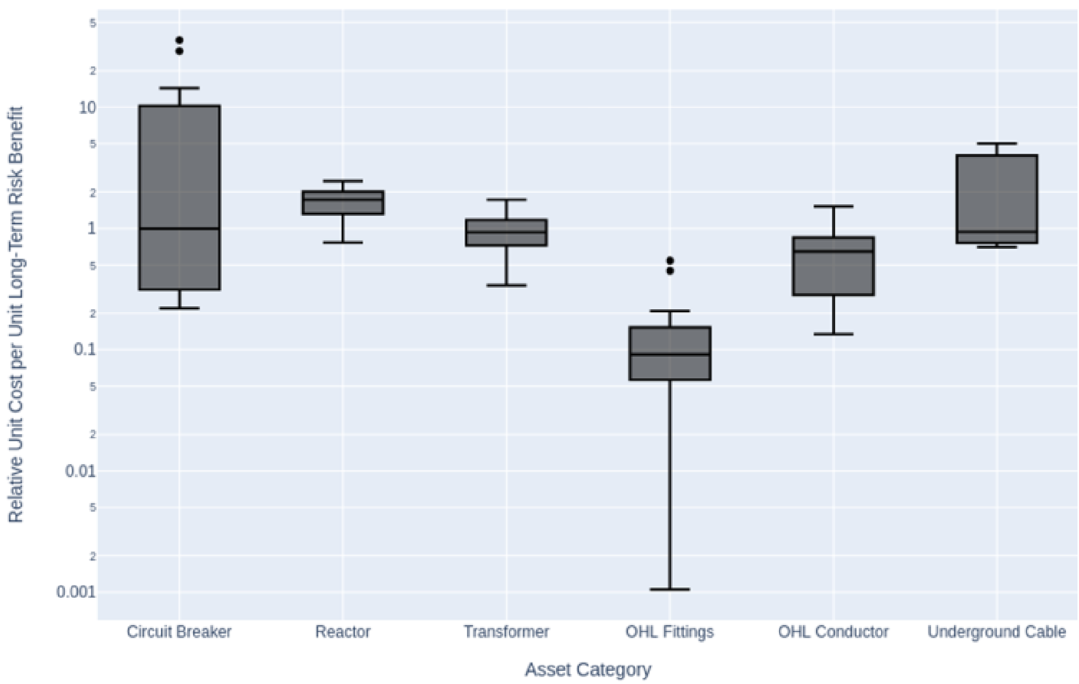
NARMs Question 2: *Do you agree the funding adjustment principles and our proposals for applying funding adjustments?*

We disagree with Ofgem's proposed funding adjustment principles and its proposals for applying funding adjustments for the reasons set out below.

Funding Adjustment Principles

The formulation of the proposed funding adjustment is problematic because the underlying needs case is flawed. The reasoning behind the requirement for the proposed funding adjustment was the perceived variation of unit cost per unit risk across asset classes. This is supposedly demonstrated for a single Electricity Transmission Owner by the figure given in appendix 6 of the Ofgem NARM Annex of the RIIO-2 Draft Determinations shown below.

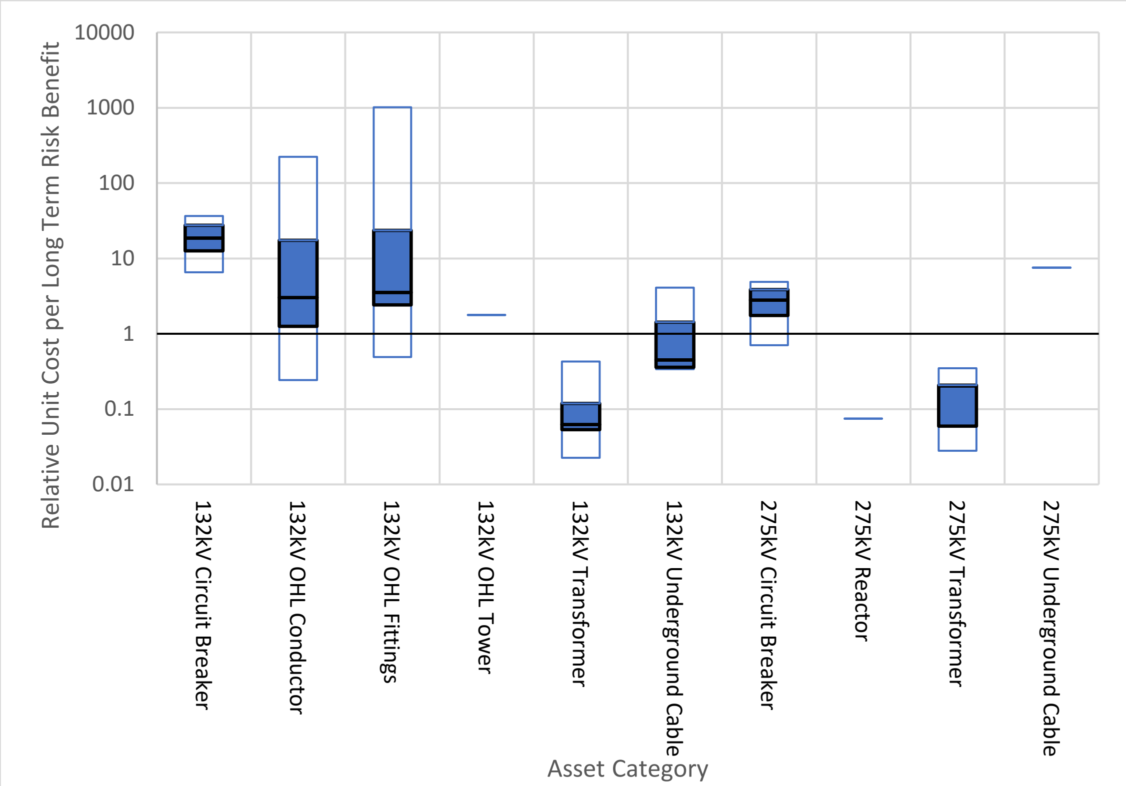
Figure 7 - Illustration of variation in the Unit Cost of Risk Benefit delivery for electricity transmission



Ofgem has not made clear how this chart was generated; however, there are two aspects which it must consider: (i) the variability of unit costs within asset types (dependant on technology and voltage), and (ii) the risk variability (also dependant on technology and voltage). Our scheme cost per risk benefit is outlined below (outliers not excluded and only includes schemes considered A1 by Ofgem for comparison purposes).

It is clear from the provided graphic below that when the assets discriminate for voltage, there is far less variation within asset categories. In addition to this, it could be possible to undertake further specification to reduce the variation even further, for example there are other variations such as differences in technology such as circuit breakers which is not currently split between AIS and GIS despite very different costs between these.

We acknowledge that even though there is less variation within OHLs for the relative unit cost per LTRB once split by voltage, the risk benefit from conductors and fittings do still vary more widely. This is because generally the risks can be far greater in the North of Scotland compared to Southern Scotland, Wales, and England due to inclement weather and the lack of redundancy (network is radial in design – not meshed), i.e. the consequence of failure on a network which is radial in design is a lot higher.



With that context established, the initial premise then put forward by Ofgem is (to paraphrase): *Due to the variation in risk benefit within and across asset categories, a TO may choose the worst risk benefit per cost for the Business Plan then, when RIIO T2 is in flight, substitute the best risk benefit per cost schemes for a windfall gain.*

While this is clearly possible from examining both Ofgem's graphic and our graphic, both of which do demonstrate that this can vary quite significantly (and our graphic providing more details on the context and reasons why), the premise is flawed and does not understand the real world complexity in implementing the risk benefit system, for the reasons outlined below.

The point of the 'risk-benefit-cost' methodologies that have been proposed for the close of RIIO-T1 and ongoing into RIIO-T2 is to demonstrate the value of schemes relative to each other so that they can be traded appropriately. It should come then as no surprise that there is significant variation as, if there were none, then 1 for 1 trades using the Risk Priority (RP) system would have been sufficient.

As our graph above shows, the variation in the unit cost of risk benefit of risk benefit delivery for electricity transmission is a lot less when split by voltage and therefore variation is not an issue and that the variations possible are easily justified. Indeed, it is a sign of good asset stewardship to focus on the actual need of asset intervention and the actual monetised risk score is irrelevant. For example, if an item of plant was to fail, then we would need to intervene on this asset (via repair, refurbishment or replacement) and the actual monetised risk score of this failed asset is irrelevant to this asset management decision. Further to this, the way in which SHE Transmission has approached our asset interventions works for RIIO-T2 - by identifying wider projects rather than single asset interventions - makes undertaking direct substitutions of asset intervention works difficult and problematic.

The final issue to address is removing the possibility that licensee's may 'game' the system by proposing high cost-low delivery schemes in the Business Plan, then changing to a low cost-high delivery scheme post Business Plan. However, it should be easy to identify if a TO is undertaking this action via review of their overall network asset health data within their submitted Business Plan so this should not be of concern. For example, if a TO is forgoing an urgently required 275 kV circuit breaker replacement (R9/R10) and instead the Business Plan is composed of a majority of OHL works which offer the least risk benefit for a high cost then it is clear that is should be challenged by Ofgem.

As the TOs have listed the asset interventions which it is planning to undertake as part of their Business Plans, backed up with Engineering Justification Papers, it would also be obvious from the number of trades requested that the initial Business Plan was never intended to be carried out. As a result, it would be impossible to undertake this action unnoticed. In addition, ignoring needed works in favour of more profitable endeavours could lead to asset failure and significant customer disconnections (and the penalties that follow).

Overall, due to the high risk involved, there is little incentive to pursue this strategy from the point of view of the TO. If this strategy was pursued it would be easily spotted, and Ofgem could also easily challenge this behaviour by disallowing trades or imposing other sanctions.

Proposal for Applying the Funding Adjustment

The application of the proposed funding adjustment i.e. utilising the final outturn unit cost of risk benefit value to determine the provided allowance, works well in theory as the allowance given is always proportional to the benefits delivered (where the relationship between risk benefit and expenditure is linearised using the Business Plan values).

However, in practice, this is not a viable method to determine the allowed expenditure for several reasons.

First, this is not in line with the overall mantra of RIIO and the Totex Incentive Mechanism (TIM), which is essentially to *'deliver x amount of benefit for y amount of allowed expenditure – if you provide more benefit for the allowed expenditure you are rewarded, if you provide less benefit you are penalised'*. Based on this mantra, the allowed expenditure should be locked at the Business Plan stage and if a TO is not performing up to standard, or better than the standard, then penalties and incentives respectively should be provided to said TO. In summary, the penalty itself should penalise TOs for poor performance; there should not be a second penalty that modifies allowed expenditure.

Second, utilising a brand-new methodology which then feeds back into the allowed expenditure introduces significant risk to TOs and could also serve to introduce the distortions in TO operations that the proposed changes were designed to inhibit. For example, if the TO has unexpected additional expenditure on a planned scheme, the TO is now incentivised to try and trade for a more risk/cost beneficial scheme in order to make up the shortfall (to try and maintain proportionality between risk benefit and cost). In addition to this, the proposed methodology is not symmetrical for dealing with any over or under spend. The NARM methodology caps any benefits achieved by the network companies for under spend to 5%, however any overspend is entirely at the risk of the network companies. This means that there is no way to recover any overspend even if it is out with our control. We strongly recommend that Ofgem ensures that the mechanism is symmetrical for dealing with any over or under spend in undertaking Non-Load related works.

Third, in order to keep non-intervention risk changes neutral, a mechanism to handle the difference between forecast and actual risk of an asset will need to be determined. This is due to the expected changes between the forecast risk value of assets and actual risk value of those at the end of the RIIO-T2 period, due to the nature of current Scottish TO's NOMs methodology. The future deterioration of an asset is calculated on a continuous scale up to a value of EOL=15, which is higher than the maximum actual risk that an asset can achieve at any given point in time EOL=10. Therefore, the actual risk value of an asset at the end of the RIIO-T2 period in known to be lower than the forecasted value even with the expected deterioration.

Further detail is required on how to mitigate the effects of changes in consequence of failure, in particular System Consequence. These issues have been discussed in the Sector and Cross Sector Working Groups and proposals made, however to ensure consistency an approach should be agreed at a TO level and be documented.

SHE Transmission considers that to keep data cleansing cost neutral as suggested[106], the changes must be agreed before any significant expenditure takes place on that scheme. In addition, this should not result in a change to the unit cost of risk benefit; the changes should be applied to the baseline values and therefore the proportionality between allowed expenditure and risk benefit should change accordingly.

If the data changes cause a scheme to be scrapped entirely, the initial costs of that scheme (any preliminary documents or site investigations) would need to be written off as allowed expenditure in order to truly be cost neutral.

Overall, the proposed funding adjustment principles does not act in the best interest of the consumer, contrary to Ofgem's principal objective, and encourages the TOs to take an overly risk averse approach. The potential change to the allowed expenditure based on final delivery encourages TOs to stick exactly to plan to minimise risk. Taking into account our further comments in response NARMs SQ3, we recommend that the only feasible approach for assessing under or

[106] See paragraph 4.13 of Ofgem's Draft Determination NARM Annex: https://www.ofgem.gov.uk/system/files/docs/2020/07/draft_determinations_-_narm.pdf

over delivery and accurate cost adjustment in the ET sector is by a scheme-by-scheme assessment through the T2 close out process. It would be up to the TOs to demonstrate its delivery against its Business Plan and providing justification for (i) trade-offs; (ii) any under-delivery; and (iii) any over-delivery through a performance assessment report.

NARMs Question 3: *Do you agree with our proposed approaches to calculating funding adjustments and to application of penalties?*

No, SHE Transmission disagrees with Ofgem proposed approaches to calculating funding adjustments and to the application of penalties for the reasons set out below.

Calculating Funding Adjustments

Discussion on SHE Transmission's position on the principles, calculation, and application of funding adjustments is covered in our response to NARMs SQ2.

Application of Penalties (and Incentives)

The application of incentives and penalties, where the incentives are defined by the DAF and the penalties are defined by PEN, do not provide enough of benefit or punishment to be effective as a mechanism to motivate TO performance.

There are basically no incentives to work to a high standard (maximum benefit of 5%), and the actual penalty imposed (separate from the revised final allowed expenditure based on unit cost calculation) is 2.5% of the delta between final allowed expenditure and baseline allowed expenditure. Therefore, both incentive and penalty are so small as to essentially become ignorable. In addition, SHE Transmission proposed costs for our Non-Load related projects within our Final Business Plan which were established through our previous knowledge and experience of our contractor prices, we therefore disagree with Ofgem's proposed "efficiency" savings which has led to a significant reduction in our allowed expenditure. This further reduction made to these project costs means that it is highly unlikely that we will be able to achieve an underspend in delivering these projects, and the penalty is a likely outcome from the outset of the price control. We fundamentally disagree with such a proposal. We believe it is essential that TOs are set a realistic allowance with an opportunity to outperform where genuine efficiencies are achieved and an opportunity to recover justifiable costs.

The final calculation of the unit cost of risk benefit is a far more severe penalty and essentially overrules the penalty and incentive system. What this ultimately means is that the encouraged approach for any TO would be to minimise collecting asset data upon Business Plan publication (as this may lead to data cleansing risks that change the outcomes promised in the Business Plan) and deliver exactly what was outlined in the Business Plan to the letter. Even if this is no longer in the interest of the public.

In the opinion of SHE Transmission this would not be consistent with the licence requirements placed upon SHE Transmission to act as a responsible TO acting in the best interest of the consumer or with Ofgem's principal objective to act in the interests of consumers. In fact, it is conceivable that the proposed funding adjustment principles will penalise acting in the best interest of the consumer.

For example:

As established previously, a TO may trade for a low cost-high risk benefit scheme if a scheme in the Business Plan has utilised more allowance than expected. There is no guarantee this would be in the consumers' best interests.

A TO may try to avoid a high cost-low benefit scheme that is not included in the Business Plan but urgently required. Due to the severe effect this will have on the final unit cost of risk benefit, the TO may try to delay this until it can fit into the next Business Plan. There is no guarantee this would be in the consumers' best interests.

A TO may avoid implementing a scheme that is not included in the Business Plan if the risk of the scheme is dominated by the consequential risks as opposed to the asset health risks. There is a risk that this will not be justified due to the vague nature of the justification requirements combined with the less documentable/subjective consequential risks (relative to asset health risks). There is no guarantee this would be in consumers' best interests.

To help illustrate the significant penalties which are caused as a result of the funding adjustment unit risk approach, we have attached some scenarios to demonstrate the impact of the funding adjustment on network companies if it was to:

- Under-deliver against target (i.e. unable to undertake one of its approved NLRE schemes), or
- Over-deliver against target (i.e. if it was to over-deliver by a similar scheme included within the Business Plan).

These scenarios illustrate that, with the proposed mechanism, there are several cases where the TO is disincentivised to act in the consumers' interests. In fact, there are several demonstrated cases where the TO is incentivised to ignore the needs of customers and essentially 'stay-the-course' of the Business Plan under any circumstances. This is clearly an unnecessary and unacceptable outcome.

Scenario 1: Harris – Stornoway (Under Delivery)

Scenario		
Ref	Harris/Stornoway	SHNLT228
EXPsc	Scheme allowance	£ 35.70
RBsc	Scheme risk benefit	8257.89
EXPbl	Baseline allowance	£ 786.46
RBbl	Baseline risk benefit	10774.2
EXPor	Outturn expenditure	£ 750.76
RBor	Outturn risk benefit	2516.3
	Over-spend	-£ 35.70
EXPaf	Final allowance given	£ 183.68
	Baseline Programme Funding	24.5%
		-£ 567.08
If Unjustified		
PEN	Penalty applied	-£ 15.07
EXPaf	Final allowance given	£ 168.61

Harris – Stornoway is an Overhead line scheme connecting Island demand by way of a long radial circuit, with no alternative Transmission supply or Distribution back feed options. This gives it an unusually high System Consequence and combined with the relatively poor asset condition gives a very large LTRB for replacement. Whilst unlikely, there are a number of Load schemes which may remove the need to replace this circuit, and the challenging terrain and weather conditions add significant risk to the timely completion of the works.

In the situation where the works were not able to be delivered, the unit cost per risk benefit for this scheme is so far above the average that even a justified under delivery of this scheme would see £567m worth of funding handed back leaving SHE Transmission with only 24% of the required funding for the rest of the T2 programme of works. In addition, if this was deemed unjustified, a further £15m penalty would be applied (nearly half the value of the scheme).

Scenario 2: Beauly (Under Delivery)

Scenario			
Ref	Beauly	SHN LT210	
EXPsc	Scheme allowance	£	89.80
RBsc	Scheme risk benefit		121.04
EXPbl	Baseline allowance	£	786.46
RBbl	Baseline risk benefit		10774.2
EXPor	Outturn expenditure	£	696.66
RBor	Outturn risk benefit		10653.1
	Over-spend	-£	89.80
EXPaf	Final allowance given	£	700.71
	Baseline Programme Funding		100.6%
		£	4.05
If Unjustified			
PEN	Penalty applied	-£	2.14
EXPaf	Final allowance given	£	698.56

Beauly on the other hand is more heavily reinforced so the System Consequence is much reduced compared to Harris – Stornoway as a result the benefit for the interventions is significantly lower. However, the interventions themselves are high cost transformers with a significant amount of non-lead assets included in the scheme cost too. As a result, the unit cost per risk benefit is below the average.

If SHE Transmission were unable to get the appropriate outage and deliver this scheme the funding adjustment would not remove the whole scheme allowance and the T2 Program would gain an additional £4m in funding. Even with the penalty for Unjustified under-delivery of £2.1m, there would be a net gain. Therefore, in this realistic scenario, the TO would actually be incentivised to not undertake this scheme as it would gain financially as a result of Ofgem’s proposed funding adjustment principle.

Scenario 3: Culligran (Over Delivery)

Scenario		
Ref	Culligran	SHNLT208
EXPsc	Scheme allowance	£ 14.30
RBsc	Scheme risk benefit	18.89
EXPbl	Baseline allowance	£ 786.46
RBbl	Baseline risk benefit	10774.2
EXPor	Outturn expenditure	£ 800.76
RBor	Outturn risk benefit	10793.1
	Over-spend	£ 14.30
EXPaf	Final allowance given	£ 787.84
	Baseline Programme Funding	98.4%
		-£ 12.92
If Unjustified		
PEN	Penalty applied	N/A
EXPaf	Final allowance given	£ 786.46

To model the scenario of a single transformer failure, an “extra” Culligran project has been used. Typically substation scheme unit cost per risk benefit sits below average, and it can be seen that if this asset failed and required immediate replacement then the adjusted funding would leave SHE Transmission £12m short to complete the job, assuming that the intervention was justified. SHE Transmission would have to take on the risk of potentially receiving no funding should the intervention be deemed unjustified at a later date.

We recommend that the only feasible approach for assessing under or over delivery and accurate cost adjustment in the ET sector is by a scheme-by-scheme assessment through the T2 close out process. It would be up to the TOs to demonstrate its delivery against its Business Plan and providing justification for (i) trade-offs; (ii) any under-delivery; and (iii) any over-delivery through a performance assessment report.

NARMs Question 4*: Do you agree with our proposals in regard to requirements for justification cases?*

Scheme Justification

For reference the required justification in the DD is outlined below:

'the outturn delivery provided a significant net benefit to consumers compared to on-target delivery;

the over-delivery or under-delivery could not have been avoided through re-planning the work, or that to do so would have been significantly less beneficial to consumers;

the over-delivery or under-delivery was due to factors that could not reasonably have been included in their RIIO-2 Business Plans at the time of output setting; and

they could not, without a significant consumer dis-benefit, have traded risk against other work in order to deliver overall baseline outputs.'

While we agree that schemes outside the Business Plan should be well justified, considering that there is already an established high bar for this justification, it is critical that the requirements are less vague. For instance:

- What constitutes 'a significant net benefit'?
- What would Ofgem consider 'significantly less beneficial'?
- What evidence is required to establish that not foreseeing the need-case at the time of writing the Business Plan is reasonable?
- What is the limit of trading before this becomes a 'dis-benefit' to the public?

It is clear that further work is needed to clarify what justification actually looks like so that clear and objective expectations and standards can be set for the licensees. In the absence of such clarity, judgement of performance is subjective, opaque and potentially arbitrary. It is essential that Ofgem provide this clarification within its Final Determinations, otherwise the network companies will start the T2 price control without a clear understanding of the risk which they are taking on and Ofgem could potentially change the goalposts over the course of the price control should it decide any of the proposals are not sufficient.

COVID-19

Given that the NARM RIIO-T2 mechanism is still being developed and will be refined throughout T2, it does not seem appropriate to apply this mechanism to T1 works that have run into T2 due to coronavirus.

Our proposal on how the longer-term impacts of COVID-19 should be addressed are set out in our response to Core Question 43.

6 Finance Annex: consultation question responses

Allowed return on debt questions

***Finance Question 1**: Do you agree with our approach to estimating efficient debt costs and setting allowances for debt costs?*

Section 5.2 within our main response to Ofgem's DD details our view supported by robust and detailed evidence as to why we strongly disagree with Ofgem's methodologies for estimating efficient debt costs and setting allowances for debt costs.

***Finance Question 2:** Do you agree with our proposal to use the iBoxx GBP Utilities 10yr+ index rather than a combination of iBoxx GBP A and BBB 10yr + non-financial indices?*

Please refer to section 5.2.3 and 5.2.4 of our main response to the DD as to why we do not believe Ofgem has correctly analysed the cost of borrowing in particular the additional costs of borrowing. We also note that the issues with the use of the Utilities Index compared to the A/BBB iBoxx non-financial corporate bond index.

***Finance Question 3**: Do you agree with our proposal that the RAV growth profile of SHET continues to be materially different to other networks and therefore warrants continuation of a bespoke RAV weighted allowance calculation?*

Please refer to the detailed analysis in section 5.2.1 of our main response to the DD as to why SHE Transmission did not request a bespoke mechanism. We have presented significant evidence and analysis similar to that undertaken in RIIO-T1 to illustrate why this is an error by Ofgem. This includes the relative growth of the RAV in T2 of TOs as well as compared to T1. We have also set out that Ofgem has not undertaken the necessary analysis considering the whole sector impact of a RAV weighted mechanism which is not a suitable mechanism for the whole sector.

***Finance Question 4:** Do you have any views on the model to implement equity indexation, as published alongside this document, (the "WACC allowance model.xlsx") or on the annual update process?*

We have set out in our main response our view of RFR indexation in section 5. We note that the equity indexation is not appropriate and if it were to be then this needs to be adjusted for the items noted in section 5.1 in particular the changes to the RFR proxy and the other parameters of the CAPM.

***Finance Question 5:** In light of RIIO-2 Draft Determinations and Ofwat's Final Determinations for PR19, do you believe that energy networks will hold similar systematic risk during RIIO-2 to water networks during PR19?*

We have set our own assessment of the relative risk of energy networks to water companies in section 5.5 of our main response. We evidence that Ofgem has not relied upon observable market data. We also note that Ofgem's qualitative analysis is not robust and we provide our own analysis highlighting that risk is materially higher in energy networks. When we reviewed Ofgem's analysis and reference to the CEPA[107] report, we note that Ofgem has summarised their conclusions more strongly than was the case in this report.

Finance Question 6: *Is there evidence of a material difference in systematic risk between: a) RIIO-1 and RIIO-2, b) distribution and transmission networks, c) gas transmission and electricity transmission, d) gas and electricity? Step-2 implied cost of equity consultation quest*

We have set out the relative risk of energy networks compared to Water as per FQ5. However, in relation to reviewing the four items above, we believe that the level of risk in RIIO-2 is higher than RIIO-1 for different reasons yet some factors are considered lower risk. We have reviewed all four items a) to d) as part of our response to this question.

At this stage we do not believe there is sufficient data to the ED framework to determine the difference in risk profile without this being overly qualitative. We do note that we believe that on a qualitative basis electricity transmission has significantly higher risk in relation to capital investment and network reliability compared to gas distribution. Considering the number of reopeners, we also note that the extent and number of reopeners also introduces a series of regulatory risks that heightens the uncertainty in the sector. The new additions proposed by Ofgem on revenue risk through under and over-recovery, the LOTI mechanisms and competition, as well as the penalties on late delivery add to the complexity and volatility of cash flows in RIIO-2 compared to RIIO-1 for Electricity Transmission. Specifically, for SHE Transmission, our risk profile has reduced since RIIO-1 due to the size of our RAV which is not going to grow at the same rate as RIIO-1 but outside of this we believe the risk has increased because of the factors mentioned above and throughout our main response.

We therefore conclude that in principle, RIIO-2 is higher risk than RIIO-1 due to cash flow volatility and uncertainty in particular due to ex-post adjustments, heightened regulatory risk and framework design, the asymmetric incentive framework, the extreme efficiency challenges, and changes to the revenue management over RIIO-2. This is in addition to the material issue of downward pressure on financeability caused by the cost of capital being set too low by Ofgem in DDs as well as the significant downside risks that we have explained in section 5.4 of our main response.

We would note that there has been concern around asset stranding noted by Ofgem in gas distribution but we have not considered this in-depth due to the uncertain and subjective nature of the analysis.

[107] CEPA, 'RIIO-2: Beta estimation issues', p. 5.

<u>Step-2 implied cost of equity consultation questions</u>

Finance Question 7: *Do you have any views on how we should consider further the gearing impact on beta and cost of capital estimate*

Please refer to the detailed analysis in section 5.1 of our main response to the DD regarding the numerous points we raise around Ofgem's considerations of beta and cost of capital estimates

Finance Question 8*: Do you agree with our interpretation of cross-checks? Step-3 allowed return on equity consultation questions*

Please refer to the detailed analysis in section 5.1 (particularly section 5.1.3) of our main response to the DD regarding why we disagree with Ofgem's interpretation of cross-checks due to their reliance upon inferior cross checks. Ofgem has erroneously placed too much weight on inappropriate evidence to force downward pressure on the CoE for RIIO-2.

We also note that Ofgem has also made significant methodological changes to force down the cost of equity in error and should have been more reliance on observable and reliable market data, finance and academic theory and regulatory best practice.

Step-3 allowed return on equity consultation questions

***Finance Question 9**: What is your view on the overall in-the-round assessment of allowed returns to equity? Is our judgement of 3.95% at 60% notional gearing reflective of the combined analysis through Steps 1, 2, and 3?*

Please refer to the detailed analysis in section 5.1 of our main response to the DD regarding why we strongly disagree with Ofgem's overall assessment of the CoE. Ofgem has made a number of errors in setting the cost of equity and ultimately has set the allowed return on equity too low.

***Finance Question 10**: What is your view on the expected outperformance estimate of 0.25% at 60% notional gearing? Do you recommend alternative analysis techniques or do you have suggested improvements to the analytical files published alongside this consultation? (a) "AR-ER database.xlsx", b) "Residual outperformance.xlsx", c) "Simple MAR application model.xlsx")*

We strongly disagree with application of an outperformance wedge to the cost of equity both in principle and empirically. Our point of principle and analysis is also supported by the Frontier report[108] whereby the introduction of a mechanism has negative incentive properties and will cause consumer detriment over the long term (i.e. more than one price control). Our analysis is based upon our review of Ofgem's 'database' of regulated company past outperformance including RIIO-1 information.

Firstly, we do not agree that Ofgem should be relying upon data from other regulatory sectors including Water and Aviation. These sectors are not relevant to RIIO-2 or indeed energy networks and therefore should be excluded. They have also relied upon historical data for pre-RIIO-1 across all energy networks for which little or no corroboration of data is possible. This data in particular prior to DPCR 5, TPCR 4 and GDCPR 4 is highly unreliable while also being different price control settlements. We therefore believe that if this mechanism were acceptable (which it is not) then Ofgem should be only considering RIIO-1 and in particular only the relevant sector such as T1 or GD1. When we narrow the analysis down to RIIO-T1 we have identified that Ofgem has actually relied upon the wrong data. Ofgem has utilised data which is inconsistent with the expected outcome of RIIO-T1 including considering post true-ups and close out mechanisms.

Given Ofgem has not been able to interpret RIIO-1 data correctly, we see no reason why any reliance can be placed on historical price controls or other regulatory sectors without any detailed analysis or reconciliation. This data is both unreliable and irrelevant and therefore when considering RIIO-T1 only we note that SHE Transmission's outperformance is not in fact 6% as noted by Ofgem[109] and is in fact 2.7% after close out adjustments and true-ups. Albeit we note that the database uses an efficiency forecast of 15% for SHE Transmission which is incorrect and prior to close out adjustments.

In addition to this, Ofgem has made large efficiency related cuts to our T2 Business Plan which is based upon our RIIO-T1 performance. When we consider the source of outperformance in RIIO-T1, Ofgem has made a number of cost adjustments to the Volume Driver spanning T1 and T2 as well as having proposed a significant change in unit rates for the T2 Volume Driver. Ofgem has also proposed indexation of Real Price Effects (RPEs) which Ofgem believes is a source of

[108] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns (Sept 2020)
[109] RIIO – 2 Draft Determinations Finance Annex: Figure 15: Forecast RIIO-1 underspend and proposed RIIO-2 efficiency gains

outperformance. These adjustments potentially eliminate all outperformance in RIIO-T1 overall (and when applying RPEs would lead to significant underperformance) as well as reducing the capacity for outperformance in RIIO-T2. This analysis could only be improved upon if the accurate data was used for T1 only and then evaluated against what outperformance is repeatable or not controllable by way of a regulatory mechanism. When we consider the structure of RIIO-T2 compared to RIIO-T1, we see a significant reduction of outperformance and more likely underperformance across the price control. The asymmetric nature of the price control and how it has been calibrated gives rise to more downside risk as we have set out in our response to the DD. **We therefore see no justification empirically to rely upon this data including the RIIO-T1 period to support any outperformance wedge regardless of size.**

Our analysis also shows that companies are more likely to underperform or at least not repeat the same level of performance in RIIO-2 Draft Determinations than outperform which undermines expected outperformance of 22-25bps estimated by Ofgem. Ofgem's supporting evidence is not robust and does not support an outperformance wedge. Ofgem's analysis contains multiple errors and flaws as well as not providing any evidence regarding the wider impact assessment of implementing an outperformance wedge which is supported by the evidence in the Frontier report[110]. We have reviewed each of the files issued by Ofgem alongside DDs below and highlighted some of the key issues with Ofgem's analysis in drawing its conclusion of implementing an outperformance wedge.

Specifically, we note that the "AR-ER database.xlsx"[111] is flawed due to a number of issues identified in our review of the data. We would note we were unable to verify a substantial amount of the underlying data prior to RIIO-1 and outside of Energy Networks while noting the RIIO-1 analysis was incorrect:

The data is heavily reliant on historical analysis of previous price controls which are no longer comparable to RIIO-2. The Frontier report[112] supports that removing this historical data alone reduces average observed outperformance from 7% to 3.7%.

This analysis covers multiple sectors which range across varying price controls and are therefore not comparable as we have noted above.

Throughout the database there are numerous gaps resulting in missing data (e.g. TPCR 3 has been excluded completely) or loose assumptions have been applied in order to create historical data i.e. totex being the total of opex and capex figures without adjustments and whole price control data being annualised crudely.

Overall this data analysis is irrelevant and not comparable to RIIO-2 so should have no weighting on calculating an outperformance wedge.

When reviewing the "Residual outperformance.xlsx"[113] file we note the following observations:

[110] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns
[111] RIIO – 2 Draft Determinations – Technical Annexes: Draft Determinations – AR ER Database
[112] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns
[113] RIIO – 2 Draft Determinations – Technical Annexes: Draft Determinations –Residual Outperformance

For ET the database is based on 2019 submitted RFPR's which includes company forecasts of complete price control as well as company estimates of enduring value adjustments to totex. These forecasts and adjustments are purely based on the individual company's judgement and are not consistent across companies and therefore do not represent a true and comparable close out position for the RIIO-1 period. Hence, data used for ET1 is not a true reflection of what the final outperformance position will be.

Ofgem has failed to reflect all adjustments for differences between RIIO-1 and RIIO-2 and so the residual outperformance analysis does not give a true reflection of what company's performance in RIIO-1 would have been under RIIO2 Draft Determinations. Adjustments excluded from the analysis include PCD's (which can account for up to 45% of companies totex allowance), NARM's, productivity challenges which are greater than T1 and therefore harder to outperform. They have also not included the impact of their benchmarking and incentives framework in particular the differences between IQI in T1 and the BPI in T2. Therefore, the analysis is incomplete and not representative of RIIO-2.

The analysis carried out by Frontier[114] has accounted for some of these missing elements and concludes that it is near impossible for companies to outperform on totex as the opportunity within RIIO-2 to do so has been stripped away. For incentives there is opportunity to outperform, however, the opportunity in RIIO2 has significantly reduced compared to RIIO-1 and the likelihood of significant underperformance in totex is more likely to outweigh any benefit from incentives.

Overall this data is misleading and is an exaggerated estimation of what the outperformance across RIIO-1 is, hence overstating a calculation for an outperformance wedge.

For the "Simple MAR application model.xlsx"[115], the Frontier report[116] also analyses the following points and why they cast doubt over the reliance on the Simple MAR application model:

The reliance on this model in Ofgem's analysis is injudicious as the data uses highly volatile market information which can then introduce volatility when setting allowed returns for the price control.

Ofgem has placed a heavy reliance on the three listed water companies. Relying on comparison to the water sector is not a true reflection of how the energy sector can outperform in RIIO-2 as this sector is not relevant to energy. This is supported by the fact the water sector is extremely lower risk compared to the energy sector as discussed in section 5.5 of our main response. This is supported by analysis by Oxera has set out in their report for the ENA and supporting analysis[117].

The MAR application model analysis relies on out of date transaction premia (the latest transaction included is dated 2018). As with the historical analysis in the AR-ER Database how much reliance can truly be put on data that is not relevant and up to date to provide useful analysis in order to estimate an outperformance position for RIIO-2.

As Ofgem has been adjusting RIIO-1 performance to attempt to forecast potential RIIO-2 outperformance, by utilising the MAR application model there is a risk that Ofgem double counts

[114] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns (Sept 2020)
[115] RIIO – 2 Draft Determinations – Technical Annexes: Draft Determinations –Simple MAR application model
[116] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns (Sept 2020)
[117] Oxera (Sept 2020) 'The cost of equity for RIIO-2'

these adjustments through both its source analysis as well as conclusions in the MAR model. This increases the risk of double counting leading to further errors.

Again, the use of the MAR Model in concluding an outperformance wedge is significantly flawed and so is not robust evidence to justify applying this to the allowed return.

Following our analysis alongside the Frontier report[118] it is clear there are significant gaps in the Ofgem supporting evidence for an outperformance wedge and highlights that when this data is updated to be more aligned to the proposed price control for RIIO-2 it is highly unlikely that companies will be able to outperform and there is significant potential for underperformance.

Finance Question 11: *What is your view on an ex-post adjustment for baseline equity returns? Is there an alternative mechanism or implementation approach that you think could better meet our stated objectives? Do you have specific views on averaging, pooling or suggested simplifications?*

As per FQ10 we do not support the use of an outperformance wedge and hence the need for the ex post adjustment would not be required if this were to be removed. Ofwat for PR19[119] has already set out its argument as to why an ex-post or adjustment to allowed returns is not required in its price control. They have noted they do not believe there has been systematic outperformance in Water and that they have struck the price control elements robustly enough that they can rely upon each mechanism accordingly. Ofgem however, has removed a significant proportion (and potentially all) sources of outperformance and there appears to be little or no justification as to why the price control cannot be set robustly as Ofwat believes for PR19.

With regards to SHE Transmissions view on an ex-post adjustment for baseline equity returns is that it reduces company's incentives to outperform as well as having a negative impact on company's financeability. The impact of the ex-post adjustment is completely dependent on the performance levels within RIIO-2 and as already previously discussed in FQ10 it is more likely that companies will underperform than outperform based on the DDs. The analysis carried out by Frontier on behalf of the ENA highlights that the ex-post mechanism has the potential to reduce the strength of incentives by up to 33% in the electricity group which is a concerning impact when this is added on top of a significantly reduced incentivised price control[120].

Ofgem's proposal for the ex-post adjustment is to apply this based on the average operational performance of the ET sector and so there is no guarantee to individual companies that they can recover the full 22-25bps. By applying this approach, it significantly reduces the incentive for companies to outperform as you are reliant on the performance of the other companies within the sector and the three transmission companies are all very different with differing price control output targets. Frontier highlights that an average group approach does not work for the electricity companies as:

[118] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns (Sept 2020)
[119] https://assets.publishing.service.gov.uk/media/5eff32803a6f4023cdba3438/Citizens_Advice_submission__2_.pdf page 10
[120] Frontier Economics: Further analysis of Ofgem's proposal to adjust baseline allowed returns (Sept 2020)

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- each licensee operates a very different network serving a different region;
- their Business Plans are far more bespoke and tailored as a result, limiting their direct comparability (for example the application of PCDs are highly individual); and
- while output regimes are broadly similar, each has been calibrated on a bespoke basis.[121]

As well as the ex post adjustment disincentivising companies to outperform it also reduces their financeability. As per Frontier's report in Ofgem's financeability assessment it has included this ex post adjustment, however, this is a flawed assumption due to:

- the uncertainty that a company will even receive an adjustment as it is highly dependent on the average performance across the sector
- the regulatory risk, there is no certainty as to how this calculation will be applied during the close out period and therefore may not materialise to the level's companies expect based on their performance throughout the RIIO-2 price control

The adjustment will be applied at close out rather than annually throughout RiIO-2 so any income generated will not materialise until the next price control and also has the potential to be offset against other close out adjustments. This again highlights our reasons for not supporting the ex post adjustment as adjustment will not incentivise companies to drive towards an outperformance position throughout the price control as there is limited certainty as to whether this reward will be applied at the end.

We have also set out in section 5.3.1 in our main response why we believe this is harmful for consumers and that Ofgem has failed to consider the adverse impact over more than RIIO-2 as a result of lost efficiency and performance for customers.

Finance Question 12: *Do you agree with our approach to assessing financeability?*

We have set out our response to Ofgem's financeability assessment in section 5.4 of our main response. We have undertaken our own analysis with supporting evidence from Oxera[122] to evaluate Ofgem's approach and we conclude that Ofgem has incorrectly undertaken their financeability assessment. As we explain Ofgem has made a series of errors and adjustments to *'mask'* a serious financeability issue caused by setting the cost of capital too low for RIIO-2 alongside ex-post adjustments, the outperformance wedge and the excessive and unrealistic efficiency challenges.

Finance Question 13: *Do you agree with our approach to determining notional gearing for each notional company?*

We have set out our response to the notional gearing assessment in section 5.4 of our main response, where explain why Ofgem has erroneously and disingenuously changed notional gearing to mask a financeability issue contrary to observed gearing levels.

[121] ibid.
[122] Oxera (Sept 2020), 'Financeability of the RIIO-2 Draft Determinations', prepared for Scottish Hydro Electric Transmission

We have explained our view of Ofgem's financeability assessment and in particular noting that their notional company definition is incorrect and these assumptions have been used to '*mask'* a financeability issue. This is set out in detail in section 5.4 including summary Table 5.7.

Finance Question 14: *Do you have any evidence that would suggest we should consider adjusting our notional company financing assumptions due to the impact of COVID-19?*

We have explained our view of Ofgem's financeability assessment and in particular noting that their notional company definition is incorrect and these assumptions have been used to '*mask'* a financeability issue. This is set out in detail in section 5.4 including summary Table 5.7.

Finance Question 15*: Do you agree with our proposal to pursue Option A?*

SHE Transmission strongly believe that licensees should be fully funded for their actual tax costs and that consumers only pay for those actual tax costs. We also believe that, as regulated networks, adopting some form of accreditation for transparency on tax would be a positive step for consumers.

Thus, taxation should be treated as a pass-through cost if licensees can demonstrate compliance (or a demonstrable equivalent level of compliance) with a tax accreditation standard. We are accredited under the Fair Tax Mark.

We do not support the alternative mechanisms proposed by Ofgem in the Draft Determinations or the proposal to pursue option A, as these do not appropriately ensure licensees pay their actual tax due. This is not in the best interest of consumers and does not recognise companies with responsible tax track records.

Finance Question 16*: Do you agree with our proposals to roll forward capital allowance balances and to make allocation and allowance rates Variable Values in the RIIO-2 PCFM?*

Ofgem's proposals to roll forward RIIO-1 capital allowances balances would result in moving to a purely notional basis of calculation for capital allowances this potentially will result in a significant under/over performance compared with our actual capital allowance performance. We would therefore support rebasing the capital allowance balances to be in line with companies actual positions to ensure companies are remunerated for the actual tax they are paying. However, an adjustment would be required to deal with the underfunding (or overfunding) during RIIO-T1 prior to making this adjustment.

We agree with the approach to make allocation and allowance rates variable values in the RIIO-2 PCFM. However, the allocation rates will have to be reviewed based on final totex allowances as per final determinations as the current allocation rates in the ET2 Licence Model[123] are based on our original totex submission within our Business Plan[124]. If the final totex profile were to differ from this then the allocation rates will need to reflect the impact of this to ensure RIIO-T1 is correct ahead of the AIP process.

[123] RIIO – 2 Draft Determinations – Technical Annexes: Draft Determinations –RIIO-ET2 Licence Model
[124] SHE Transmission: A Network for Net Zero, RIIO-T2 Business Plan

We also note that RIIO-T1 tax allowances and actual costs will need to be trued-up to avoid timing issues and intergenerational issues increasing significantly over the RIIO-2 and future periods.

***Finance Question 17**: Do you agree with the proposed additional protections? In particular: a) do you have any views on a materiality threshold for the tax reconciliation? Do you think that the "deadband" used in RIIO-1 is an appropriate threshold to use? b) Do you have any views on our proposals to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1? c) Do you have any views on the proposed process for the Tax Review? d) Do you have any views on the proposed board assurance statement?*

Under SHE Transmission's proposal to treat tax as a pass-through based on a fair tax accreditation or similar this would eliminate these differences and the requirement for the majority of the following additional protections.

a) do you have any views on a materiality threshold for the tax reconciliation? Do you think that the "deadband" used in RIIO-1 is an appropriate threshold to use?

A tax reconciliation is already currently included within the annual RFPR submission and expanding on this for a more detailed full reconciliation would create a significant amount of work with little or no value. There can be material differences in the way a notional tax allowance is calculated versus a company's actual tax payments and reconciling the two can be extremely difficult when taking into account timing adjustments and notional balances etc.

If this were to be implemented, an appropriate materiality threshold being applied would be required given the resource intensive nature of the work, however, the deadband amount would appear to be too low. We see no reason why the materiality threshold should not be aligned with other re-openers, i.e. 1% of base revenue. Aligning with a materiality threshold (0.33% of base revenue or 1% corporation tax change applied to type A tax trigger events) that is proposed to be removed in RIIO-2 and was related to a mechanism that has minimal resource implications, does not seem a reasonable approach. For the avoidance of doubt, we do not see this as been conflated with what the threshold should be for the tax reopener mechanisms which we do not believe is required if a pass-through mechanism is adopted with enhanced certification like FTM.

b) **Do you have any views on our proposals to retain the Tax Trigger and Tax Clawback mechanisms from RIIO-1?**

We agree with retaining the tax trigger and tax clawback mechanisms from RIIO-1, with the materiality threshold for type A events is removed.

c) Do you have any views on the proposed process for the Tax Review?

Following our position on tax being treated as a pass-through proposal based on our Fair Tax accreditation we disagree with any form of reopener and see no need for one given our proposal. We believe that the introduction of new reopeners adds regulatory complexity which adds no value to consumers. Network companies should only be remunerated for the tax they pay, no less and no more. Under the fair tax accreditation companies tax affairs are already subject to tax reviews and so a further tax review by another external party would be unreasonable.

A reopener would only be required where a notional allowance is the preferred option and this would be more appropriately dealt with through a close out adjustment, unless considered material during a price control. Under a notional allowance companies should also be incentivised to be as tax efficient as possible and a tax review would need to ensure that legitimate under/over performance is not eradicated.

We do not support proposals for a Tax review during the price control.

d) Do you have any views on the proposed board assurance statement?

We do not support introduction of a board assurance statement and Ofgem has failed to substantiate what purpose and benefit this actually serves. SSE plc as with most large businesses are already required by HMRC to publish their UK tax strategy setting out details of their attitude to risk, relationship with HMRC, etc.

The amount of corporation tax paid by a license holder is unlikely to ever equate to the amount of their tax allowance and so it is also not the role of the board to be assuring whether Ofgem mechanisms, e.g. tax allowance calculation, are appropriate.

As already stated SSE is accredited under the Fair tax mark and surely this provides satisfactory confidence and assurance around the actual tax paid by SHE Transmission.

We also note that that HMRC[125] require a Senior Accounting Officer (SAO) to ensure the company establishes and maintains appropriate tax accounting arrangements to allow tax liabilities to be calculated accurately in all material respects. We therefore believe there is more than sufficient assurance and obligations placed on the company without adding further assurances from another third party not responsible for the tax affairs of companies.

[125] https://www.gov.uk/hmrc-internal-manuals/senior-accounting-officers-guidance

Return adjustment mechanism questions

Finance Question 18: *Do you agree with our proposal to introduce a symmetrical RAMs mechanism as described above?*

We do not agree with the proposal to introduce a symmetrical RAMs mechanism as previously stated in our Business Plan[126] the proposal is more likely to cause harm than good to consumers in RIIO-2. Ofgem has failed to set out the long-term impact of this mechanism and whether or not there is any proven advantage to consumers, investors or companies. Based on the Draft Determinations, Ofgem has introduced negative weighted incentive proposals and stripped away the opportunity to outperform and therefore the mechanism is irrelevant and will provide no or little value.

Analysis, as per the report carried out by first economics[127], also supports our objection to introducing a RAM mechanism as it emphasizes that earned rewards by companies are part and parcel of a healthy regulatory regime and should not be adjusted by regulators claiming it is to protect against failures within the setting of the price control.

Finance Question 19: *Do you agree with our proposal to introduce a single threshold level of 300 basis points either side of the baseline allowed return on equity?*

Our analysis carried out on Ofgem's proposal to introduce a single threshold level of 300 basis points (bp) either side of baseline allowed return on equity excluding Business Plan incentive and debt/tax performance supports our response to FQ18 on the irrelevance of the RAM mechanism.

Our analysis uses the base data in the RIIO-T2 Draft Determinations including proposed base totex, incentives, closing RAV, and sharing factor. Based on this analysis if SHE Transmission were to max its output incentives cap or collars this would only account for circa 50 bp out of the 300bp in the RAM mechanism. In order to then trigger the 300bp threshold SHE Transmission would then need to out/underperform on its base totex by circa 40%. Due to the level of out/underperformance in both incentives and totex required to trigger the mechanism it would be highly unlikely this would be reached and so questions why an additional mechanism needs to be added to the price control that will add little value. Ofgem's own analysis illustrates this in Figure 22 of their Finance Annex for their RoRE analysis which shows more downside potential than upside potential with a significant gap to the RAM cap and collar. We also note that with the outperformance wedge of 22bps-25bps, the cap and collar of the RAMS mechanism (if we agreed with it), needs to be adjusted to -2.75% to 3.25% to account for the outperformance wedge. We note that we do not agree with the outperformance wedge or RAMS mechanisms as set out in our response to the DDs.

Finance Question 20*: Do you have any other comments on our proposals for RAMs in RIIO-2?*

As per responses to FQ18/19 we do not agree with Ofgem's proposal for RAM's in RIIO-2 and do not believe Ofgem has justified a robust case for what value this additional mechanism will add to the price control.

[126] SHE Transmission: A Network for Net Zero, RIIO-T2 Business Plan- Finance Annex
[127] http://www.first-economics.com/earwakerfincham.pdf

***Finance Question 21**: Do you agree with our proposal to implement CPIH inflation?*

Ofgem has not yet undertaken any analysis to justify this transition immediately and why a transition period was not considered as part of the consultation process akin to PR19. We have made this statement throughout our submissions over RIIO-2 and in particular note in section 5.4 of our main response that the immediate switch and acceleration of cash flows is to solve a financeability problem temporarily and yet fails to do so without a number of other inappropriate assumptions regarding the notional company.

***Finance Question 22**: Do you agree with our proposals, including the policy alignment for GT and GD, and to recover backlog depreciation for GT RAV additions (2002 to 2021) over 20 years from the start of RIIO-2?*

N/A to the ET sector. We are comfortable with depreciation policy for SHE Transmission and continued transition to 45 year asset life by the end of the RIIO-2 price control.

***Finance Question 23**: Do you agree with our proposed assumptions for capitalisation rates?*

We do not agree with the idea of changing capitalisation rates on an annual basis either for outturn values or for allowances. This was a well discussed topic at the outside of RIIO-1 as part of the RIIO Handbook whereby the equalisation of capex and opex to totex and the application of a capitalisation rate was a clear policy decision at that time. This was focused primarily on aligning incentives on capital and operating costs and ensure the most appropriate investment and expenditure was incurred for the benefit of consumers. We believe the changing capitalisation rate would necessitate a change in the incentive properties for totex which is not the intended requirement. Also, we note capitalisation rates are not supposed to be used to support financeability excessively and are in essence to be the natural rate based on historical and forecast rates set at the outside of a price control.

Ofgem has not undertaken any analysis to set out why this approach would be appropriate for RIIO-2 and in particular the adverse incentive properties it generates for totex when choosing between opex or capex. We proposed a single rate for the RIIO-2 period based on our assessment of outturn expenditure bearing in mind ex-ante totex and uncertainty mechanism related totex similar to what was undertaken in RIIO-1. We do not believe that introducing further uncertainty and revenue volatility by varying capitalisation rates is appropriate and would introduce complexity into the price control unnecessarily.

We note that Ofgem has incorrectly calculated our capitalisation rate within DD by not adjusting for capitalisation Closely Associated Indirects (CAIs) in line with accounting standards as set out in the SSMD[128] and previous price controls. Ofgem estimate a capitalisation rate of 81% whereas the actual capitalisation rate is 88% compared to our proposed 90% for the full price control.

***Finance Question 24:** For one or more of the aggregations of totex we display in Table 40, should we update rates ex-post to reflect reported outturn proportions for capex and opex?*

As we note above, we do not agree due to the adverse incentive properties it introduces to totex which goes against the principles of RIIO. The equalisation of incentives through the Totex

[128] Ofgem SSMD – Finance Annex (May 2019)

Incentive Mechanism and use of a single capitalisation rate was to avoid these adverse incentives between opex and capex. We have seen no analysis to justify this change in approach and believe it would be a material change in regulatory policy without adequate evidence, analysis or justification on Ofgem’s part to deviate from a policy position set out at the price control. We actually believe Ofgem is using this mechanism to avoid dealing with a financeability problem and has incorrectly interpreted the purpose of the capitalisation rate and its impact on consumers.

RAV opening balance questions

***Finance Question 25**: Do you agree with our proposal to use the closing RIIO-1 RAV balances as opening balances for RIIO-2?*

Yes, we agree with the RIIO-1 RAV balances as opening balances for RIIO-2.

***Finance Question 26:** Do you agree with our proposal to use estimated opening RIIO-2 balances until we have finalised the closing RIIO-1 RAV balances?*

Yes, we agree in principle with the RIIO-2 estimated opening RAV balances as submitted in our Business Plan being used as placeholder, however, a number of adjustments will also need to be taken into account to ensure the most accurate forecast position is being taken into account. These adjustments include:

- Ensure estimated opening balances account for any elements that can be forecast including allowances are included.
- Estimated RAV associated with the approved Shetland link for expenditure and anticipated allowances that relate to financial year 20/21.
- The appropriate treatment of TIRG RAV balances in line with the Licence Condition 6F in particular the direction issued by Ofgem for adjusting the opening allowances and extending the construction and incentive period by 1 year as per Table 8 of their direction[129].

As long as the above adjustments are accounted for accordingly then we agree with a placeholder RAV opening balance until the final closing RIIO-1 RAV position is determined after close out.

129 Ofgem (Jan 2017) 'Determination on SHE Transmission's additional funding request and Opening Asset Value for the Beauly-Denny electricity transmission project'

RIIO-1 Close Out questions

Finance Question 27: *Do you agree with the three categories of adjustments outlined below?*

Yes, we agree with the three categories of adjustments outlined in the Ofgem Draft Determinations in principle. A few things which will need to be accounted for include adjustments to opening RAV balances as per FQ26 response and capital allowances adjustments as per FQ17 response.

Also, within the legacy MOD adjustments as per FQ26 response SHE Transmission will incur spend for the approved Shetland link in financial year 20/21 and so allowances will have to also be adjusted accordingly in order to calculate the legacy MOD position accurately

We also note that items such as pass-through adjustments and as noted above arrangements for the TIRG value for 2021/22 as per the licence condition noted in FQ26.

Finance Question 28: *Do you agree with our approach in using estimated values for closeout adjustments until we are able to close out the RIIO-1 price controls?*

Yes, we agree in principle with the approach in using estimated values for closeout adjustments. To ensure these estimates are as accurate as possible at this time they should be based on the proposed enduring value adjustments submitted as part of the 19/20 RFPR submission on the 31st August 2020 as well as the calculation of the legacy MOD based on 19/20 actual expenditure submitted on 31st July 2020.

It should also be noted that the enduring values included within the RFPR reflect what the RIIO-1 totex performance should have been on an annual basis but does not account for the mechanics of how this will be adjusted at close out, this would need to be confirmed prior to estimated values being used for closeout adjustments. The agreement of how close out adjustments will be made will also need to account for any adjustment required for revenue particularly excluded services (TCA/sole use entry and exit).

We also note that the revenue model is required for RIIO-2 to account for pass-through adjustments and incentive values from RIIO-T1 as well as the final year under the TIRG licence condition note above in FQ26.

Disposal of assets questions

Finance Question 29: *Do you agree that proceeds from the disposal of assets during RIIO-2 should be netted-off against totex from the year in which the proceeds occur?*

Yes, we agree that the proceeds from the disposal of assets during RIIO-2 should be netted-off against totex from the year in which the proceeds occur. This is consistent with RIIO-1 principles.

Finance Question 30*: Do you agree that we should carry out a review where an asset is transferred to a holding company and then subsequently sold to a third party?*

Yes, we agree in principle with a review being carried out where an asset is transferred to a holding company and then subsequently sold to a third party as this is in line with the licence condition relating to asset ownership (Standard Condition B3) where we currently have to seek approval from Ofgem within RIIO-1 in certain conditions. We would not deem a review necessary for assets that are non-operational or redundant as we would deem these to be disposed of as scrap as per FQ29.

Time value of money questions

***Finance Question 31**: Do you agree with our proposal to apply one interest rate to revisions to PCFM inputs and charging errors, based on a short-term cost of debt?*

As part of the ENA we commissioned a joint report from First Economics[130] to review the Ofgem proposals in particular the time value of money. We note that John Earwaker summarises the nature of prior year adjustments within the regulatory framework stating the following:

'I find it hard to conceive of a reason why the financing costs involved in these situations should be any different from the calculated cost of capital. I note that CEPA in its July 2020 paper for Ofgem[131] makes the argument that "the way Ofgem treats prior-year adjustments may entail a different, lower level of risk for companies compared to the main allowed cost of capital".

John Earwaker summarises why this is not appropriate and that the nature of any changes in the PCFM should be in relation to the cost of capital since that is how investment is funded. To characterise the risk profile to being different and therefore requiring a different short term debt rate is inappropriate. We see no real evidence from CEPA or Ofgem that justifies this material change in policy and is in fact more likely to harm investment by ignoring the large timing differences caused by the significant delay in reopener mechanisms compared to expenditure requirements within RIIO-2.

***Finance Question 32:** Do you agree with the margin-based approach, and the methodology used to calculate a margin of 110bps?*

As we have noted we do not agree with this methodology and in fact the approach should be to use the prevailing cost of capital only. Ofgem has incorrectly created this methodology and at such a late stage without adequate consultation and engagement with the sector. We are therefore not supportive of this analysis or policy position.

***Finance Question 33**: Do you have any reason why the marginal cost of capital for revisions to PCFM inputs and charging errors should remain distinct from each other, or why WACC may remain a more appropriate time value of money for a particular subset of prior year adjustments?*

We have set out with supporting evidence from First Economics[132] as noted in FQ31 that the WACC is the most appropriate given the nature of investment and funding of cash flows over the RIIO-2 period. It is likely adjustments will last for more than one year given the two year lag and likely impact of reopener decisions on allowances and expenditure requirements. These adjustments and funding requirements would therefore not be fully funded by short term debt and would in essence rely on longer term funding over the period and the associated buffer or cost of carry as we have set out in Section 5.2 of our main response. If Ofgem had undertaken the nature of the timing of funding in RIIO-1 for example, it would see that with less reopeners some adjustments have taken several years to unwind. For example, we will have spent in the region of £300m by the time revenue is received for the Shetland Link in RIIO-2, that cannot be funded out of short

[130] First Economics (Aug 2020), 'RIIO-2 Prior Year Adjustments', prepared for the ENA.
[131] Ofgem (2020), Prior-year adjustment uplifts.
[132] First Economics (Aug 2020), 'RIIO-2 Prior Year Adjustments', prepared for the ENA.

term working capital or debt and therefore should be compensated for the cost of capital or WACC over the period.

Revenue forecasting questions

Finance Question 34: *Do you agree with our proposal to include forecasts for most PCFM variable values for the purposes of the AIP?*

We do not support dynamic forecasting. A forecast based approach would still involve an element of forecasting and so, there is no guarantee that it would reduce the magnitude of future true ups. Such an approach does not reflect the reality of a price control, would be likely to lead to more volatility in tariffs and would be more difficult to understand. The introduction/retention of key uncertainty mechanisms should help to reduce volatility as opposed to complex forecasting exercises.

Finance Question 35: *Considering re-openers as set out in these Draft Determinations, do you agree with our proposal to exclude them from any forecasting? If not, please submit specific examples or analysis of the potential materiality of actual spend versus initial allowances.*

As per FQ34 we do not agree with including forecasts within the PCFM as forecasts will add an additional layer of complexity to the revenue process and potentially lead to more volatility within tariffs. If forecasts were to be introduced, then the forecasting of reopeners should also be included as due to the significant value of reopeners that potentially could be actioned throughout the RIIO-2 price control companies should be given the option to forecast both future allowances as well as expenditure within the PCFM.

The primary value of any forecasting would be to allow revenue to be set including reopener mechanisms to avoid financeability or timing of revenue concerns albeit added complexity is the cost of such a mechanism. We would need to understand why forecasting ex-ante funding but not reopeners would be beneficial for companies or consumers with the added complexity. We would need to see and understand the mechanics in particular the logistics of reporting and setting tariffs on an annual basis to ensure any potential forecasting was workable and pragmatic while avoiding unnecessary complexity and volatility. **We would welcome engagement on this area with Ofgem as this is the first time this issue has been raised by Ofgem and we have yet to see the detailed analysis or workings as noted above.**

Finance Question 36*: Do you agree that additional reporting on executive pay/remuneration and dividend policies will help to improve the legitimacy and transparency of a company's performance under the price control?*

As per the our RIIO-T2 Business Plan[133] we explained SSE's approach to making dividends and remunerating our employees. We do not agree that additional reporting on executive pay/remuneration and dividend policies on an annual basis will help to improve the legitimacy and transparency of a company's performance under the price control. The Draft Determinations provide no supporting evidence as to why additional reporting is required by third parties and so it is inconsistent with Ofgem's information collection and reporting simplification objectives. Ofgem has also provided no supporting evidence to mitigate the potential legal considerations that may arise with the collection, holding and publication of this information. As stated within the original response from the ENA there is of course an interplay between the requirements of relevant statutes under which Ofgem and our members operate and report, which raises a further

[133] SHE Transmission: A Network for Net Zero, RIIO-T2 Business Plan

question as to whether the proposed requirement can be considered consistent with good regulation.

Executive remuneration: We do not support providing additional information on executive remuneration. This information is already included in the Statutory Financial Statements for the SSEN companies, prepared under applicable statutory accounting frameworks and which are all subject to external audit under ISA's. As highlighted by the ENA a requirement to disclose personal data/information for publication is not one that Ofgem should impose and also conflicts with requirements in respect of good corporate governance and the disclosure of directors' remuneration set by Parliament, the FCA or any exchange on which a company's securities are listed. It is not clarified in the Draft Determinations where this additional information would be disclosed but if the proposal were to be the RFPR, this document would not be subject to the same reporting or auditing standards.

Dividend policy: As stated in our Business Plan our dividend policy is based on a range of factors considered by the Board of Directors including delivering our Business Plan, maintaining our investment grade credit rating and providing an appropriate rate of return to shareholders. We do not agree with the requirement to report on this annually as Ofgem does not provide a robust case for what value annual reporting of this would add. In our Business Plan we highlight that our dividend policy for the RIIO-T2 period does not deviate significantly from our historical approach and that each year will consider our commitments to deliver our Business Plan while ensuring we comply with our licence requirements to maintain an investment grade credit rating and for Availability of Resources.

Base Revenue definition and ODI cap/collar questions

***Finance Question 37**: Do you agree with the proposed definition of Base Revenue?*

We do not agree with the proposal to remove the tax allowance from the base revenue definition as per our response in FQ15 tax should be treated as a pass through and therefore should be aligned with the treatment of all other passthrough items in base revenue including business rates. Ofgem has failed to explain how the tax allowance would therefore be treated within revenue if it were to be excluded from the base revenue definition.

***Finance Question 38:** Do you agree with the proposal to fix the values used for ODI caps and collars at Final Determinations?*

We disagree with the proposal of option B which is to fix the values used for ODI's caps and collars at final Draft Determinations as this would be based on base revenue as per final Draft Determinations and will exclude the impact on revenue of any future reopeners/UM's that are approved. Based on the current proposals for the RIIO-2 price control a material amount of spend is likely to flow through the UM's and so will then impact the potential cap/collar of ODI's. Using the RIIO-ET2 Licence Model[134] as an example the impact on base revenue on average between the base case totex and the illustrative totex including UM's is circa £28m on average per year which would be excluded from the ODI cap/collar calculation if base revenue were to be used. Based on this SHE Transmission would propose option A to use the ex-post, 'recalculated' version of base revenue which will then account for the impact of agreed UM's/reopeners throughout the RIIO-2 period and is aligned with how this currently is calculated in RIIO-1.

It is also worth noting that our incentives will be based on our overall network performance and interaction with our stakeholders and not just the transmission network that is expected based on the ex-ante funding position. **This would misalign the incentives and the revenue associated with the network to which those incentives are assessed. This is simply incorrect.**

[134] RIIO – 2 Draft Determinations – Technical Annexes: Draft Determinations –RIIO-ET2 Licence Model

7 SSEN Transmission Draft Determinations Response Submission: list of supporting annexes

Category	Annex name
Main Response	T2BP-DD-QRD-002 Main Response Document
Individual Question response	T2BP-DD-QRD-001 Response to Ofgem's Draft Determination questions (Draft v1.0) THIS RESPONSE
SHE Transmission Supporting Evidence	T2BP-DD-SHE-001 SSEN Transmission - Consumer Value Proposition (CVP)
	T2BP-DD-SHE-002 SSEN Transmission Stakeholder Feedback
	T2BP-DD-SHE-003 SSEN Transmission - Group Bios
	T2BP-DD-SHE-004 SSEN Transmission - Business Plan Incentive (BPI)
	T2BP-DD-SHE-005 SSEN Transmission - Totex Incentive Mechanism (TIM)
	T2BP-DD-SHE-006 SSEN Transmission - Uncertainty Mechanisms - Volume Driver
	T2BP-DD-SHE-007 ET Q6 Annex 1 SSEN Transmission IIG ODI Draft Determinations Impact Assessment
	T2BP-DD-SHE-008 SSEN Transmission - the role of Groups (Core Q1)
	T2BP-DD-SHE-010 True up, Logging Up and Re-openers - SSEN Transmission RIIO-T2 Proposals
	T2BP-DD-SHE-011 - SHET_TIM_Cost Confidence Workbook
	T2BP-DD-SHE-012 Annex 1: Q&A on Pre-Action Correspondence and Post Appeal Review
	T2BP-DD-SHE-013 SHET Q4 Annex 1
	T2BP-DD-SHE-014 SHET Q4 Annex 2
	T2BP-DD-SHE-015 SHET Q4 Annex 3A
	T2BP-DD-SHE-016 SHET Q4 Annex 3B
	T2BP-DD-SHE-018 - Business Plan Incentive Summary Workbook (BPI)
	T2BP-DD-SHE-019_ET4_LCP Ofgem Mechanisms-Workings
	T2BP-PAP-0016 PCF 10920 Update
	T2BP-PAP-017 PCF for T3 LRE Schemes
	T2BP-PAP-018 PCF for T3 NLRE Schemes
Confidential response – additional information requested from Ofgem	SSEN Transmission - Cyber Resilience IT & OT Plan Assessment
Independent Consultant Reports	Oxera: Ofgem's TOTEX assessment approach at the RIIO-ET2 draft determinations: a review, August 2020
	Oxera: Critique of RIIO-2 ongoing efficiency analysis, August 2020
	Oxera – Financeability of the RIIO T2 DD's (SSE report)
	Oxera – The Cost of Equity for RIIO-2 (ENA report)
	Oxera – Asset Risk Premium relative to Debt Risk Premium (ENA report)
	NERA – Review of Ofgem's DD additional costs of borrowing and deflating nominal IBOXX (ENA report)

	Frontier - Further analysis of Ofgem's proposal to adjust baseline allowance (ENA report)
	First Economics – Productivity Growth (ENA report)
	First Economics – Prior Year adjustments (ENA report)
Engineering Justification Papers – Non Load Related Expenditure	T2BP-EJP-0027 Sloy Substation Works Justification Paper
	T2BP-EJP-0027 Level 1 Condition Assessment - Sloy GT1 FINAL
	T2BP-EJP-0027 Level 1 Condition Assessment - Sloy GT2 FINAL
	T2BP-EJP-0027 Level 1 Condition Assessment - Sloy GT3 FINAL
	T2BP-EJP-0027 Level 1 Condition Assessment - Sloy GT4 FINAL
	Summary Sloy GT1
	Summary Sloy GT2
	Summary Sloy GT3
	Summary Sloy GT4
	T2BP-CBA-0001 Sloy Substation Works CBA Re-submission July 2020
	T2BP-EJP-0032 Kilmorack & Aigas Substation Justification Paper
	Aigas_Kilomorack_RIIO-ET2_CBA_Template_v1.6
	Level 1 Condition Assessment - Aigas GT1 FINAL
	Level 1 Condition Assessment - Kilmorack GT1 FINAL
	R_MRB_SHET_SHNLT206_v4_Aigas
	R_MRB_SHET_SHNLT207_v4_Kilmorack
	SSE Phase 1 Contaminated Land Assessment Final 24 June 2020
	SSE Phase 1 Contaminated Land Assessment Final Risk Review Table 24 June 2020
	Summary Aigas GT1
	Summary Kilmorack GT1
	T2BP-EJP-0035 Culligran Substation Justification Paper
	Culligrain_RIIO-ET2_CBA_Template_v1.6
	Level 1 Condition Assessment - Culligran GT1 FINAL
	R_MRB_SHET_SHNLT208_v4_Culligran
	Summary Culligran GT1
	T2BP-EJP-0036 Deanie Substation Justification Paper
	Deanie_RIIO-ET2_CBA_Template_v1.6
	Level 1 Condition Assessment - Deanie GT1 FINA
	R_MRB_SHET_SHNLT209_v4_Deanie
	Summary Deanie GT1
	T2BP-EJP-0027 Broadford Substation v1.1
	Broadford_RIIO-ET2_CBA_Template_v1.6
	R_MRB_SHET_SHNLT2012_v4_Broadford-SystemUpdate
	T2BP-EJP-0040 Quoich Tee Substation Works Justification Rev1.1
	R_MRB_SHET_SHNLT2013_v4_QuoichTee
	T2BP-EJP-0041 St Fillans Substation Works Justification Paper Rev1
	Level 1 Condition Assessment - St Fillans GT1 FINA
	St Fillans Cost Benefit Analysis
	R_MRB_SHET_SHNLT2014_v4_StFillans
	Summary St Fillans GT1
	T2BP-EJP-0043 Keith Substation Works v1.1

	R_MRB_SHET_SHNLT2022_v4_Keith
	T2BP-CBA-0011 Keith Substation Works CBA
	T2BP-EJP-0044-St Fergus Mobil Rev1.1
	R_MRB_SHET_SHNLT2031_v4_St Fergus Mobil
	St Fergus Mobil_RIIO-ET2_CBA_Template_v1.6
	T2BP-EJP-0042 Tummel Bridge Substation Works Justification Rev1.1
	20200810_Tummel Bridge Cost Benefit Analysis
	Level 1 Condition Assessment - Tummel Bridge GT1 FINAL
	Level 1 Condition Assessment - Tummel Bridge GT2 FINAL
	Summary Tummel Bridge GT1
	Summary Tummel Bridge GT2
	T2BP-EJP-0006 Transmission Communications Upgrade v7.6
	T2BP-EJP-0006 Transmission Communications Upgrade Appendix A
	T2BP-EJP-0006 Transmission Communications Upgrade Appendix B
	T2BP-EJP-0003 Resilience - Operations Centre Justification Paper
	T2BP-EJP-0003 - Operations Centre Rev 1.1
Engineering Justification Papers – Non Load Related Expenditure	Attachment 1 Operational Functions Needs and Risks Summary EPRI August 2020
	Attachment 2 EPRI-SSE Control Centre Review Project FINAL V1.0a
	Attachment 3 Control Centre Risk Benefit Analysis Tables
	TCC_RIIO-ET2_CBA_Template_v1.6
	T2BP-EJP-0050 Dynamic Line Rating
	DLR CBA - Reinforcement Deferral Benefits FINAL
	T2BP-EJP-0050 Dynamic Line Rating Engineering Justification Paper (Note: ICMP has had the Dynamic Line Rating component broken out into a new paper).
	T2BP-EJP-0012 Integrated Condition Performance Monitoring Justification Paper
	T2BP-EJP-0012 Integrated Condition Performance Monitoring Justification Paper and
	T2BP-EJP-0013 Materials Management and Warehousing Justification Paper Rev3
	Warehouse Condition Report
	Warehouse_RIIO-ET2_CBA Rev 3
	T2BP-EJP-0013 Materials Management and Warehousing Justification Paper
	T2BP-EJP-0029 Foyers Substation Engineering Justification Paper
	Foyers RIIO-T2-CBA
	R_MRB_SHET_Foyers
	T2BP-EJP-0050 Willowdale Substation Engineering Justification Paper
	Willowdale RIIO-T2-CBA
	R_MRB_SHET_Willowdale
	T2BP-EJP-0034 Beauly-Deanie-Aigas Substation Engineering Justification Paper
	Beauly-Deanie-Aigas RIIO-T2-CBA
	R_MRB_SHET_Beauly-Deanie-Aigas
	T2BP-EJP-0037 Peterhead Substation Engineering Justification Paper Rev1.1
	T2BP-EJP-0023 Kinardochy Reactive Compensation Consultation Response