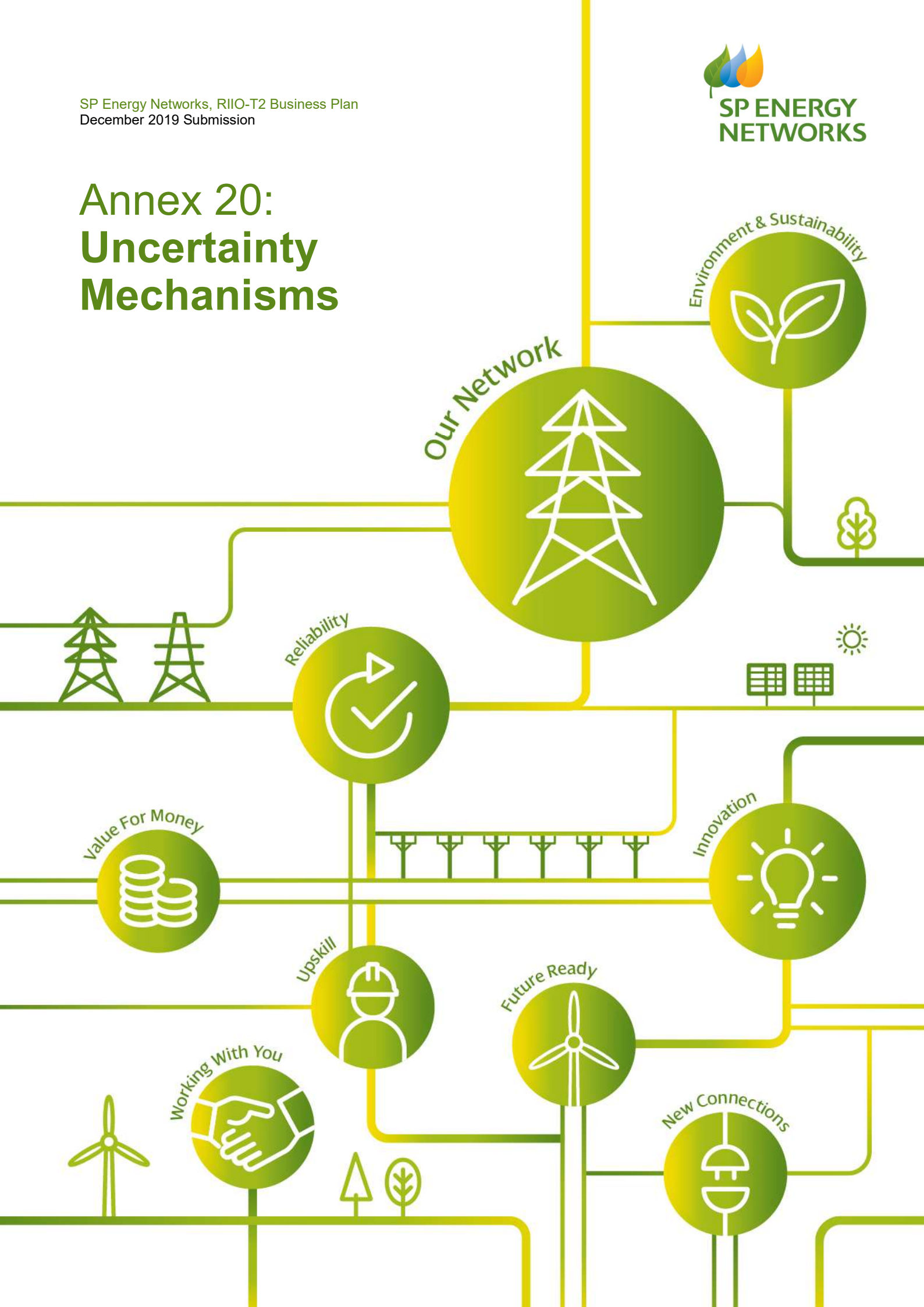
Annex 20: **Uncertainty Mechanisms**



CONTENTS

INTRODUCTION

In developing our RIIO-T2 business plan, we have only included baseline cost allowances where the need is clearly justified, timing of expenditure is understood, and costs are certain. However, some areas of our operations naturally incur material costs which are difficult to forecast years ahead as they are subject to uncertainty outside our control. Consequently, no allowances are made in our business plan for costs which we perceive as uncertain and subject to significant change over the course of RIIO-T2 as this approach could pose financial risks to both SPT, connected customers and the end consumer. Instead, we are supportive of Ofgem's proposals to accommodate for such uncertainties in our business planning with the use of uncertainty mechanisms, which provide flexibility for the adjustment of revenues over the course of RIIO-T2.

We have grouped the mechanisms into three categories corresponding to the overarching sources of uncertainty.

The three categories are as follows:

- **Energy system uncertainties for Net Zero** - this area broadly includes uncertainties related to our efforts in meeting the Net Zero target that may arise across the energy system. From our experience in RIIO-T1, we are relatively confident these factors will influence our cost base, however the timing and volume of expenditure related to each source of uncertainty vary and are not accurately predictable at the time of developing this business plan. Therefore, we propose a number of different mechanisms to cover the different changes that may materialise. These include mechanistic approaches for low value or high-volume uncertainties, and more bespoke reopeners where the costs and volumes are unclear. These are vital to enable us to respond to these needs as they arise over the course of RIIO-T2.

- **Legislative, policy and standards uncertainty** - this area of uncertainty pertains to external bodies making legislative or policy changes which may impose new technical or operational obligations on our business. In particular, complying with legal obligations introduced by new legislation or Government policies is likely to give rise to unavoidable (and unpredictable) additional costs. This is particularly significant due to the forthcoming election and new government which will be in place post the publication of the RIIO-T2 business plan. Whatever the outcome of the election, there is clearly scope for material developments in energy policy. This category relates to anticipated amendments to our business environment which we are aware of but cannot prevent or predict accurately at this time. We therefore propose a reopener mechanism which would provide an opportunity to review the legislative and regulatory landscape and ensure we're equipped to respond to any new requirements prompted by external stakeholders. To minimise the administrative requirements on Ofgem, it is our view that rather than designing a range of separate reopeners to review various legislative changes individually, a single coordinated reopener window is sufficient to address a range of uncertainty sources with individual applications provided in this window for each uncertainty which requires to be considered. Section 9 of this appendix identifies the various legislative/regulatory areas where we foresee possible upcoming reviews that may affect our expenditure exposure over the course of RIIO-T2.

- **External financial uncertainty** - the last category identifies established uncertainty mechanisms to cover the changes related to the funding arrangements for network operators. This includes taxation, funding indexation and other charges which are subject to change and adjusted accordingly.

It is our view that the uncertainty mechanisms we are proposing for RIIO-T2 are to address material risk, and we have considered how the risk to both TO and customers is effectively managed. Taking this approach ensures the end consumer is protected from unnecessary expenditure which could result from premature inaccurate cost estimates or unjustified works. We have therefore taken the approach of only including certain costs within our baseline, proposing to make use of uncertainty mechanisms to make appropriate adjustments once more information becomes available.

We have actively worked with the other Transmission Owners to share experiences of the various mechanisms that were employed in RIIO-T1 to learn from how these operated in practice. The proposals build on this experience and also reflect some of the common thinking on the approach that is being taken for RIIO-T2 to ensure greater consistency than RIIO-T1 where each TO had a range of bespoke mechanisms.

Stakeholders have identified a number of other uncertainties including the prospect of a further referendum on Scottish Independence, other changes to the energy landscape which emerge from the forth coming general election and other

'unknown unknowns'. Not every eventuality in this category can be accounted for in the uncertainty mechanisms and a degree of pragmatism will be required in the drafting of the RIIO-T2 licences to account for these uncertainties.

As identified on page 139 of our RIIO-T2 business plan, uncertainty mechanisms can take various forms including:

- **Volume drivers** – calibrated at the start of the price control, these automatically adjust the revenue we recover to cover the costs that can reasonably and efficiently be expected when a defined volume of activity is delivered. An example of this in RIIO-T1 is for generation connections. We recovered a fixed amount of funding for each MW of generation which we connected to cover the costs associated with the connection.
- **Unit cost allowance** – a schedule of efficient unit costs is agreed with Ofgem at the start of the price review for predefined activities required to address the uncertainty. Revenue is provided in line with these unit costs based on predefined events being met.
- **Reopeners** – these are forward-looking revenue adjustments made within the period. They are triggered either by a threshold being reached or at a set point in time. They allow for us to propose an adjustment to our allowances to deal with any uncertainty that couldn't have been anticipated at the start of the price review. They require agreement with Ofgem before an adjustment is set.
- **Pass through items** – we incur the required costs which would be assessed by Ofgem after the event once data on actual expenditure is available. An example from RIIO-T1 is for business rates; changes to these cannot be predicted before the price review but are obligatory costs that we must incur.
- **Indexation** – for costs which can be tracked utilising recognised indices. This adjusts our allowances in line with them.

These different approaches require different levels of intervention from Ofgem and Transmission Owners in their justification and tracking over the course of the price review. Where costs are known, or a statistically relevant data set is available, but the volume of the activity is unknown; volume drivers or unit cost allowances have been utilised. These have the advantage of requiring a low level of ex-post review as the efficient costs are assessed as part of the business planning process.

Pass through or indexation have been utilised where there is no clear volume of activity. For indexation of costs, a separate metric is required to link any changes against.

Reopeners are used where both costs, volumes and or timing are difficult to forecast as the nature of this expenditure is project specific. A reopener requires a network operator to separately justify the need and efficient costs of addressing the change which has arisen. This will result in a cost to the network owner to provide a robust justification, and also Ofgem to assess the reopener application for such a modification to be approved. These are only proposed where the level of uncertainty is high, and the above mechanisms are not appropriate.

In this document we have sought to provide a detailed justification and proposed mechanism for each area. We recognise that as these develop into licence conditions further work will be required to ensure all caveats are addressed. If our proposals for any uncertainty mechanisms are rejected, an adjustment to our RIIO-T2 business plan ex-ante allowances may be required to ensure that we have suitable funding for the associated area.

All costs in this document are in a consistent price basis as the business plan data tables for consistency.

Summary of mechanisms

		Uncertainty source	Type of UM	Frequency/ trigger	Estimated cost exposure
Energy systems uncertainty for Net Zero	**1**	Generation connections	Volume driver	As required	£506M
	2	Demand connections	Volume driver	As required	£40M
	3	Major boundary upgrades- Strategic Wider Works	Reopener	Load relater projects >£100m in value	One known project with cost range £1.7 – 2.6Bn.
	4	Net zero operability changes	Unit cost allowance	Triggered by ESO STP planning request or compliance with relevant standard	£150M
	5	Net zero transition reopener	Reopener	Load related projects >£25m in value	Unknown
	6	Uncertain non-load projects	Named projects with agreed allowance	Triggered by named uncertainty being confirmed	£146M
	7	Whole system 'coordinated adjustment mechanism'	Reopener	TBC by Ofgem	Unknown
Legislative, policy and standards uncertainty	**9**	Legislative changes following Brexit	Reopener	Triggered by legislative changes in years 2023 and 2026	Unknown
		Legislative changes for environmental and climate change			Unknown
		Physical security (PSUP)			~ £2M/site
		Wayleave review adjustment			Unknown
		Planning requirements			Unknown
		Non-rechargeable diversions			Unknown
		Flood resilience			~ £6M
		Cyber security			~ £10M
		Black start			Unknown
		Energy data taskforce requirements			Unknown
		Environmental enhancements			~£13-15M
External financial sources of uncertainty	**10**	Financial uncertainty mechanisms	Various	Annual	Unknown

ENERGY SYSTEMS UNCERTAINTIES FOR NET ZERO

1.0 GENERATION CONNECTIONS

1.1 Issue that the mechanism addresses

As the Transmission Owner (TO) for the central and southern Scotland, SPT have a licence obligation to facilitate the connection of generation to the network in our geographic area. Our system is crucial to the delivery of the Government's renewable energy objectives due to its location in an area of outstanding renewable resource and our role as an energy corridor within the GB transmission system.

Over the past decade, we have seen a rapid change in the levels of generation seeking to connect to the network. Figure 1 demonstrates that for wind generation alone, the volume connected has grown by more than 150%. SPT's analysis using the National Grid Future Energy Scenarios 2019 identifies that wind generation is expected in all scenarios to continue to grow. The range of uncertainty in this period is very large, in 2026 the Future Energy Scenarios identify a 4GW difference between the highest and lowest scenario.

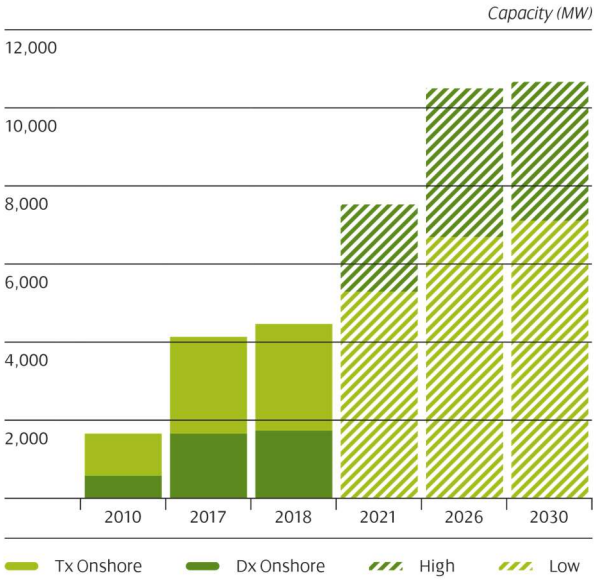


Figure 1: *Generation Projections*

These scenarios are supported by the number of applications which we have seen for new connections to the network with over 150 applications received since April 2018.

It is clear the generation landscape is constantly changing; this can be attributed to several factors.

The volume of generation – this is uncertain due to factors such as incentives and the overall planning landscape which is dependent on Government and local planning policies.

Generation technology – we have seen rapid changes in the past such as the establishment of FiTs which led to major, rapid growth in solar. Onshore wind is continuing to progress subsidy-free in Scotland and Offshore wind is being incentivised through Contract for Difference mechanism (CfD).

Location – Scotland continues to see the largest growth in onshore wind and has a high proportion of offshore wind. Within our network we have seen high concentrations in the Dumfries & Galloway area, as well as the Borders. The distance of these generators from existing network infrastructure and the capacity in this region will drive the costs associated with facilitating them on the network.

At present, SPT have over 5GW of generation connections which are contracted to connect over the next ten years. From experience, we know that not all of these will progress due to consenting issues, funding etc. Many of these will be displaced by new projects continuing to emerge over the course of RIIO-T2. However, scope, timing and cost remain largely unknown and it would be inefficient to include all projects in the business plan as we do not know which projects will progress and which will cancel. An uncertainty mechanism is required which will allow recovery of efficient costs that are incurred to facilitate new generators as required through the course of RIIO-T2. There are a large number of projects which can emerge and progress with little prior warning to us.

1.2 Justification for the mechanism

As a Transmission Owner, we have an obligation in our licence to provide an efficient, economic and timely connection to those seeking to connect to the National Electricity Transmission System (NETS). Currently generation levels are increasing with indications that this trend is likely to continue, driven by Government setting high and challenging renewable generation targets for the future. As explained above there is still a large element of uncertainty regarding where generation will connect, when it will connect and the size of the generator. With our licence obligation to connect generators regardless of these factors it is vital that funding be made available and that it appropriately remunerates for the connection infrastructure required.

We have identified a baseline of 900MW based on a detailed review process covering planning/consent status, contracted position, current development and numerous other factors. We believe the baseline is well justified, credible and is consistent with the ENA common scenario. To facilitate this generation connecting, 2,027MVA of system capacity will also be required to ensure that this generation can access the GB market. This is deemed to be shared use capacity under the definition in the CUSC.

The remaining contracted projects were deemed as uncertain and it would be inefficient to include all contracted generation projects in the plan as many will change scope or drop away. The use of an uncertainty mechanism means additional costs are incurred only when these additional projects or changes materialise. We believe that this is more appropriate than the alternative approach of seeking to anticipate such costs within an ex-ante forecast with ex-post adjustments to reflect actual costs incurred.

1.3 Ownership of associated risks

Under the Connection Use of System Charging (CUSC) methodology a portion of the costs of connection are typically borne by the connecting party, and the remainder funded by end consumers. The risk that a connecting party cancels works for which costs have been incurred are mitigated by connection customers being required to provide security to cover infrastructure costs. This ensures that a developer carries the risk of a project incurring costs and then being terminated and that these costs are not passed to end consumers.

We have only included projects in our baseline plan that we have a high confidence in. An uncertainty mechanism provides additional flexibility and reduces the risk to end consumers. The risk that a fixed allowance creates is (i) end consumers may pay more than they need to if a smaller volume of work is needed; and (ii) a fixed allowance also risks SPT not having the funding to provide connections when it is obliged to do so in accordance with its licence. Against that background our proposal is for a symmetrical mechanism. Revenues are reduced if baseline targets are not achieved, providing protection for consumers, and conversely, SPT receives additional revenue to cover the costs of additional efficient works, should output reach levels above baseline.

Any under or over spend (the overall cumulative spend) will be subject to the totex incentive mechanism (TIM) which incentivises further efficiency and innovation, as well as providing a risk sharing between company and end consumers.

1.4 Type and description of mechanism

An ex-ante forecast of generation has been made based on a detailed review of all projects to identify those with the highest confidence of connecting. Many of these projects are already in construction or well progressed in terms of planning processes. This forms the 900MW and 2,027MVA outlined in the Business Plan.

Generation connection costs are comprised of two elements – sole use infrastructure and shared use infrastructure

Sole use infrastructure assets are defined in the CUSC Section 14 as "those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party".

Shared use infrastructure assets are the transmission infrastructure works associated with the connection of more than one new or additional generating station to a part of the licensee's Transmission System (or connected to a distribution system which in turn connects to a part of the licensee's Transmission System).

Both encompass different types of work; therefore, the generation connections uncertainty mechanism has been split into two parts to accommodate both aspects of generation infrastructure.

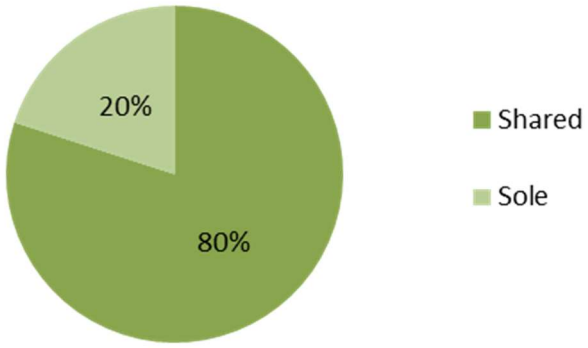


Figure 2: *Percentage of total T2 generation connection capex*

Shared use infrastructure works reinforce the network to accommodate for new generators and increase capacity for load to flow to areas of demand. This makes up the bulk of generation infrastructure investment, approximately 80% of SPTs expenditure related to shared use works.

All projects were subject to an extensive qualitative assessment to understand which should be included in the RIIO-T2 baseline for submission. Standardised assessment criteria were applied to each project looking at the following areas:

- **Contracted status** – track record of changes to contracted date due to variations/re-engineering/developer requests.
- **Developer Track Record** – Previous experience (if applicable) of developer to obtain a level of confidence.
- **Local Authority/Planning** – Local Authority and region to allow for review of previous trends for rejecting/granting an application. Also providing insight in to planning issues for developments.
- **Consent Status** – Understanding the current status and level of project maturity.
- **Financial Position** – Reviewing the financial status of developer e.g. level of securities, in place for projects where available.
- **Development status** – Analysing at what stage of development each project is in e.g. given minimum development time scales is the current energisation date likely to be met.

Using the information obtained from the above criteria, a higher confidence view of generators more likely to connect in T2 and thus form part of the initial ex-ante allowance for T2 was obtained. Projects included in the baseline had a higher confidence in all the above areas. Where any uncertainty remained regarding connection date then these projects would be subject to an uncertainty mechanism.

Several different approaches to funding uncertain projects were considered for T2 such as reopeners and volume drivers. We do not believe that a reopener is appropriate because this would not allow us to progress projects with sufficient timing as we would need to wait till the reopener period to ensure funding is arranged. Additionally, based on our experience in RIIO-T1, we expect this mechanism will be used extensively and a reopener risks adding unnecessary delays and a large

amount of work on Ofgem's part to assess these reopeners on a frequent basis. Feedback from stakeholders and customers is that timing is critical to these projects and any unnecessary delay for a reopener may compromise the success of a project. A volume driver would provide better flexibility ensuring allowance is available. This is consistent with the approach all TOs have had in RIIO-T1.

Sole use infrastructure works are driven by the connecting party. One of the main proxies for these customers is the capacity (measured in MW) which they are seeking to connect. Shared Use infrastructure (measured in MVA) relates to the capacity built to accommodate generation. The simplest metric for such works is £/MW and £/MVA, which is tied to these metrics, to cover the entire allowance (similar to the T1 approach for sole use) was first considered, however this does not reflect the varied drivers of cost which are not fully captured by the capacity connected/created.

Further investigation into the scope of projects and lessons learned from T1 identified that there are three main drivers for connection projects in addition to the capacity required: the costs for substation works (SS), overhead lines (OHL) and cable (UGC). Figures below represent % of total contracted investment for each driver.

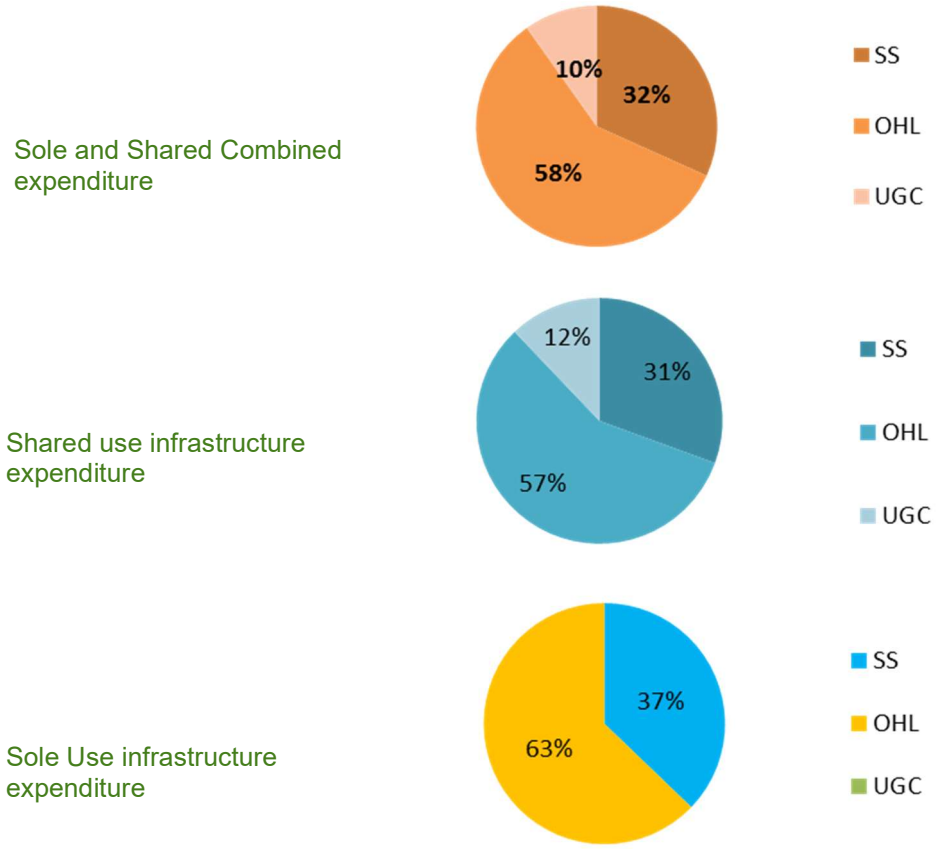


Figure 3: *Proportion of total contracted investment for each driver*

Using this data, it is evident that distance to existing infrastructure (directly linked to the length of the overhead line) is the primary driver in generation costs accounting for 58% of total contracted expenditure. This led to a further refinement to further disaggregate the volume driver to consider linear assets and substation works.

Due to the unique nature of T1 projects including extensive works in south west Scotland which resulted in the construction of a new and extensive 132kV and 275KV network, we did not feel these projects accurately reflected the work required in T2 and are unlikely to be replicated. Results may then be skewed and provide a volume driver that is not suitable for the types of projects required in T2. T1 costs were therefore not used as part of the modelling discussed in the next sections.

Overhead line costs

In the T2 period we have a variety of overhead line projects currently to provide infrastructure to connect new generation. Figure 4 below shows the length and cost of all overhead line projects. With this data set we have used simple linear regression to identify the relationship between the costs and overhead line length as shown in figure 4.

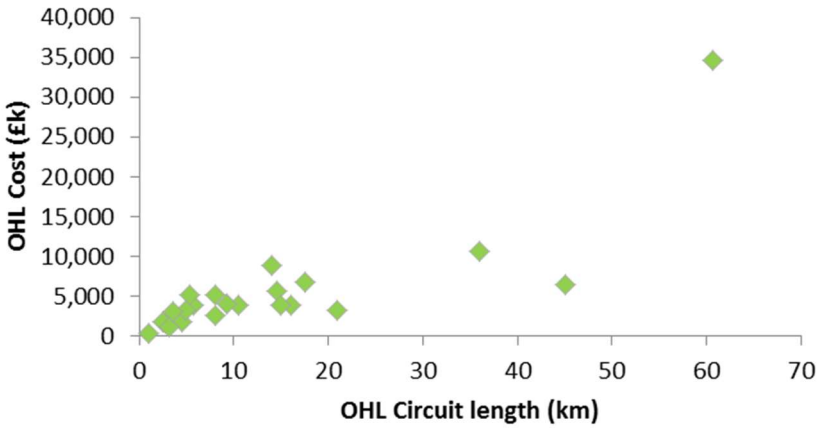


Figure 4: T2 Overhead Line Projects

Utilising all the data points above which include all data (shared and sole use) and considering these separately, the volume driver rates would be £575k per cct km for sole use infrastructure and £336k per circuit km for shared use infrastructure. From this it was evident that there appears to be different drivers for overhead line projects due to the difference in average rates between sole and shared use.

Further analysis into the shared use overhead line projects showed that projects can be split into two different types of work; new build and reconductor. This split is not applicable to sole use as this will always require the construction of new assets to facilitate the connection.

We identified difference in costs between voltages and types of overhead line. The use of 275 and 400kV overhead lines is very limited and an insufficient number of projects were available to have any relevance in this analysis. From experience, the costs associated with wood pole construction lines varies significantly to tower lines due to differences in footprint, material costs and time to construct. This is conveyed in Figures 5, 6 and 7 below. Figure 5 plots the costs and length of new build wood pole 132kV overhead lines, figure 6 shows new build tower circuits and figure 7 132kV reconductoring works.

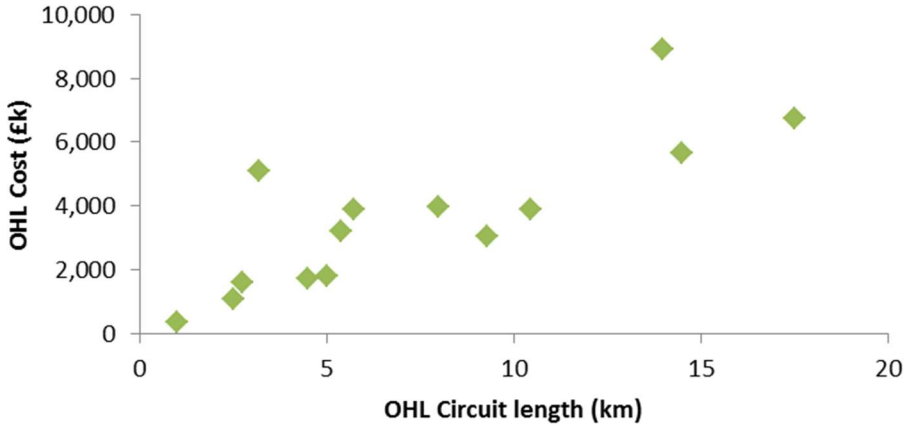


Figure 5: 132kV New build wood pole overhead line costs by length

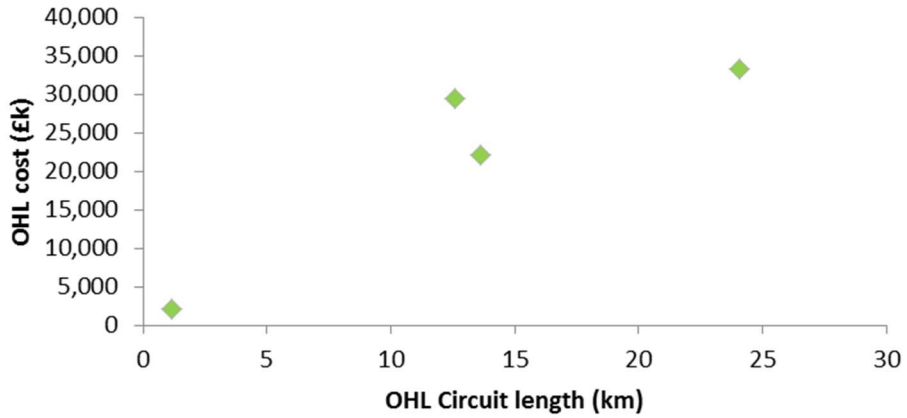


Figure 6: 132kV Tower Line circuit costs by lengths

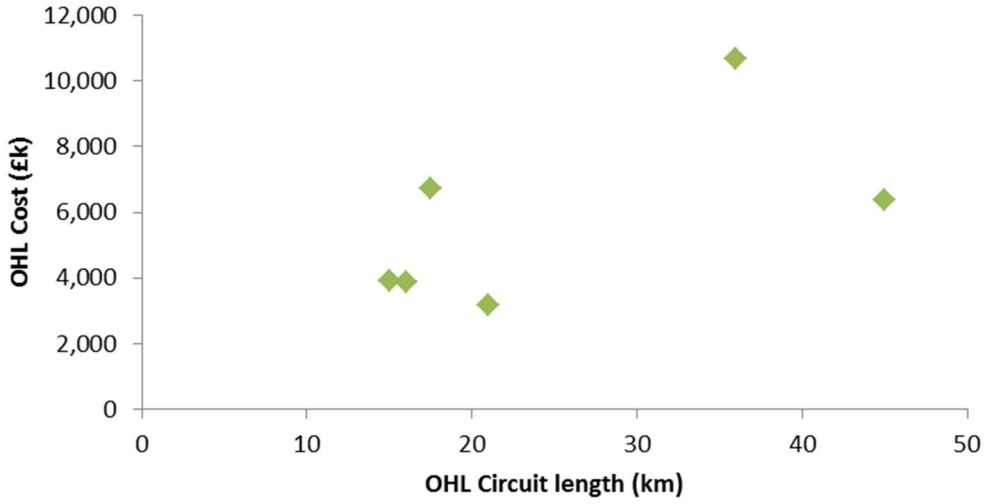


Figure 7: 132kV Reconductor overhead line costs by length

The costs for new build overhead lines include poles/towers, new fittings, securing land and other new construction overheads. Reconductoring makes use of the existing support structures and land rights and as shown in Figure 7 is significantly lower cost per km. Additionally, it can be seen the significant difference between wood pole and tower line construction from the projects shown.

Using the above data sets a volume driver rate of £613k per circuit kilometre for 132kv wood pole overhead lines, £800k per circuit tower line and £210k per circuit kilometre of reconductoring has been derived which is based on the mean cost per km. Additionally, utilising linear regression, the estimated least squares regression line for each of the above graphs was also used in the modelling. This provides greater granularity of costs however adds more complexity to the calculation of costs as it involves a fixed cost component as well as the variable circuit length.

A small number of projects include 275kV or 400kV overhead lines which accounted for some of the significant outlier projects, none of which are included in our high confidence baseline. This was not deemed sufficient for analysis to set an efficient volume driver rate. Due to the high value and low volume of these projects it is proposed to cover any 275kV or 400kV overhead line works through the 'Net Zero Reopener' as these tend to be in response to system wider works and transfer capability and in excess of the materiality threshold.

The above analysis provided different approaches for volume drivers that could be utilised in modelling with the option of having a single rate for all overhead line works or by breaking them down into different types of work.

Substation costs

Sole use substation works do not have the same variety of scope as shared use and therefore a closer correlation between the MW of generation facilitated and the cost is possible to derive for all works. For example, a connection will typically involve a new feeder bay at a substation and limited other works. The range of data for RIIO-T2 contracted projects is shown below for all voltage levels.

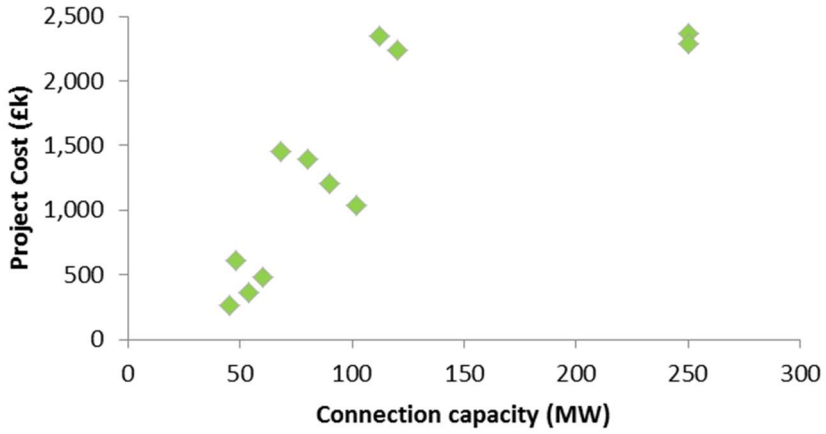


Figure 8: T2 Sole Use S/S Infrastructure costs and MW outputs

Figure 8 identifies a correlation between substation costs and the additional connection capacity. From this relationship, a £k per MW rate to fund all substation works for sole use projects is proposed. From the data set above, this would equate to £14k per MW using the average rate of all projects. Separately, a rate that would utilise a linear equation (representing the least squares regression line from Figure 8) could also be considered which would be (£8.93k*MW capacity)+£387.34k. This would introduce additional complexity in the administration of the volume driver by providing a fixed cost per project and an additional £k/MW connected. Outliers have been removed from analysis. The criteria for outliers and treatment of these will be discussed later in the paper.

For shared use infrastructure there was not a clear correlation between the MVA capacity created and the cost on the same basis as shown in figure 9.

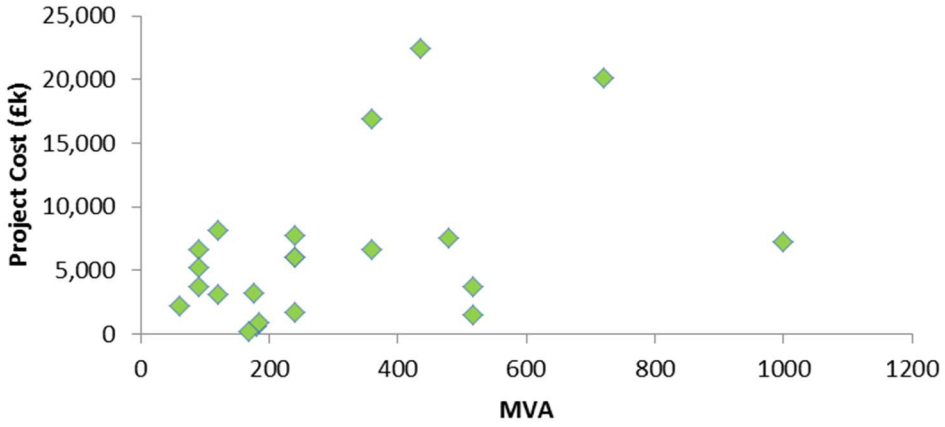


Figure 9: Shared Use Substation costs and MVA outputs

Figure 9 shows no direct correlation between the capacity created and associated cost. Therefore, a simple £ per MVA approach is unlikely to be suitable to represent all projects. This approach was still considered for modelling using a rate determined from the above data – £20k per MVA capacity created which is based on the arithmetic average cost per MVA of capacity.

Substation costs were disaggregated into rates for specific types of work for shared use infrastructure due to the variety of scope that this could involve. When looking at the scopes for shared use infrastructure works three main types of work were identified:

- new substation build/extension which would include the cost of the land purchase, associated civils as well as a substation equipment including transformers, switchgear and other non-lead assets
- transformer build/uprate which would require the installation of a new transformer as well as associated switchgear and other non-lead assets
- general substation work, for example the installation of a circuit breaker or other non-lead assets

This approach would look at a different £/MVA rate for general substation work, transformer installations and substation new build/extensions. An example of one subset of how different cost drivers could be grouped is shown in Figure 10 for projects which involve the addition of a transformer. Transformer project costs remained consistent (relative to the size of the Transformer) and a relationship can be proposed based on the £/MVA using the transformer capacity. This was calculated to be £32k/MVA. Please note that this cost includes the cost of all other assets not just the transformer.

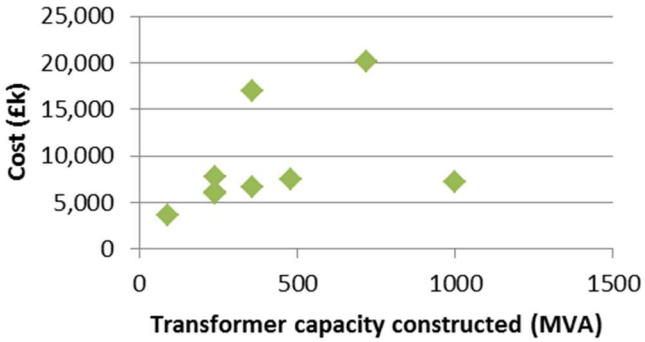


Figure 10: T2 Shared use projects with transformers - cost by capacity

Projects involving new build or substation extensions were grouped together to provide a rate for these types of schemes as they have significantly different cost elements as a result of the need for additional land purchase. From reviewing each scheme it was found that costs and outputs varied across projects.

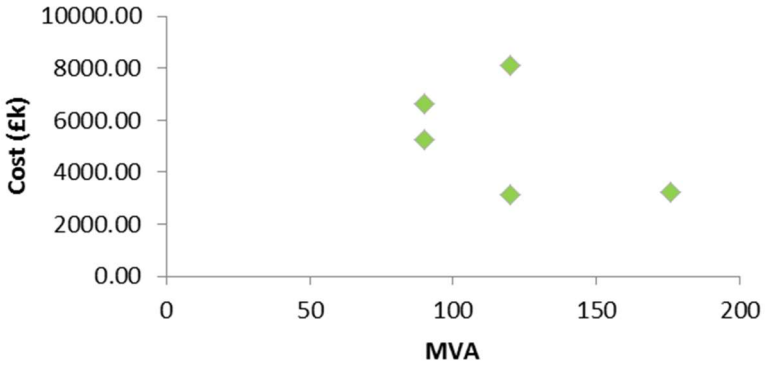


Figure 11 New Build/S/S Extension Shared Use Projects – cost by capacity

Using the data set for these projects an average of £44k/MVA was obtained for modelling purposes. Again, this rate would be used to fund all substation elements of such type of project.

Finally, for general substation work, involving work with no transformers or extension to an existing site, a rate of £14k per MVA will be used for modelling. This was found using the data set below in Figure 12 and taking the average rate per scheme. Works involved in these schemes are varied and there did not appear to be as strong a correlation between costs and outputs.

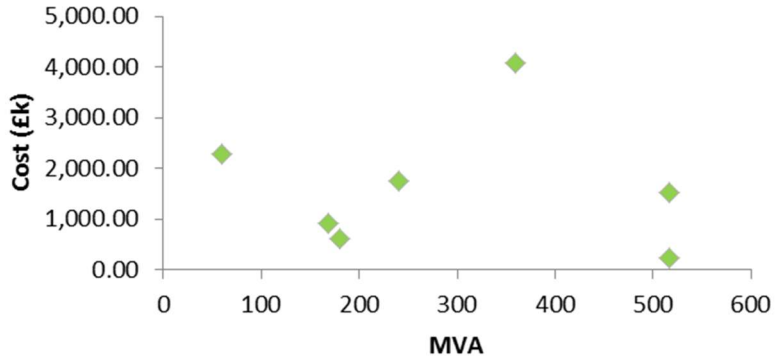


Figure 12 General S/S Work Shared Use Projects - cost by capacity

Once more, a further approach looked at the linear regression that represented each area: substation (including general S/S work, transformer installations and S/S new builds/extensions) and overhead lines. The estimated least squares regression line for each area was then used to determine allowances. An example of this can be found in Figure 13 below.

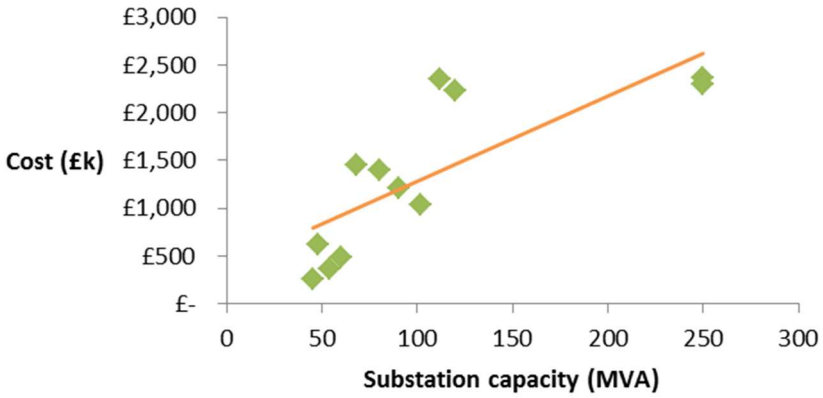


Figure 13: T2 Sole Use - Substation Projects with Linear Equation

This was also replicated for the disaggregated substation approach previously discussed to provide linear equations for each driver. Once more outliers were not used in the above analysis.

Cable costs

Cable costs were removed from our analysis due to a small data set. Very few shared use projects use cable solutions and sole use cables are generally funded by customers. We are proposing a schedule of rates for cable solutions to ensure a fair rate for the different solutions that may be required. There are a small number of projects requiring an SPT funded cable solution so whilst we do not envisage this part of the mechanism being utilised often, it will still be required to ensure efficient funding is made available should they be required under infrastructure works. This will require further work but we intend to replicate the approach of NGET in RIIO-T1 and have engaged with other Transmission Owners on developing a collective schedule of rates based on the current rates used by NGET in their RIIO-T1 licence.

Outliers

Several projects due to their large scope or output could not be used to provide an average rate or be tied to a line of best fit. It was found that including these in analysis and modelling greatly skewed data and could result in excessive over and under performance depending on which were delivered.

From reviewing these projects, it was identified that the most significant outliers below the linear best fit line were OFTO projects which had a high output per £k compared to all other projects. Additionally, two further projects were above 250MW were identified and found to affect results. Their impact was also reviewed individually.

In order to identify which projects are deemed as an "outlier" above the line, different criteria were considered. For example, projects with overhead lines with a circuit greater than 15km were further assessed to ensure these projects were not overly contributing to volume driver rate and overall performance in within modelling. However, these were not deemed to be affecting results and were therefore kept in.

It was identified that schemes with costs that were more than double the volume driver rate were considered outliers. These projects are relatively small in number, but their large cost and associated volumes have a significant influence on the slope of the regression line.

Additionally, any scheme greater than £25m or with a MW output of greater than 250MW was individually assessed for impact and not included in the analysis.

Outliers were not used in the calculation of volume driver rates or for modelling purposes.

Volume driver options

From this analysis, four main approaches were considered:

1. Single rate volume driver for sole and shared use infrastructure (£/MW and £/MVA)
2. Simple disaggregated volume driver (£/MW and £/MVA for substation works and £/cct km for linear assets split by voltage and work type)
3. Disaggregated volume driver (£/MW and £/MVA for substation works with shared use split up into three separate areas and £/cct km for linear assets split by voltage and work type)
4. Linear regression based volume driver (using linear regression analysis to determine allowance for substation works and linear assets) which is more complex but uses a more detailed statistical approach

To understand the consequences of the different approaches, a Monte Carlo analysis was undertaken on the full portfolio of RIIO-T2 projects with the four different volume driver approaches. The Monte Carlo analysis simulated 10,000 random generation combinations (iterations) with a distribution of results obtained with the aim of identifying which volume driver provided the most cost reflective allowance.

Both the sole and shared use data was included in this analysis to understand the impact both drivers would have on total generation allowance. The model includes all contracted T2 projects to give a wide data set that represented all potential permutations. The analysis looked at baseline projects and all remaining uncertain projects to provide as large a data set as possible to inform volume driver rates and analysis ensuring all current T2 works are reflected.

All projects, irrespective of whether they have been included as part of the Business Plan submission, have been designed to the same level and standard as per our legal obligation to provide the customer with an accurate quote. A number of uncertain projects were subject to review by Arcadis alongside baseline projects to ensure they are equally efficient. Furthermore, analysis is focused on the cost borne by SPT. All remaining expenditure is funded directly via customer contributions.

The analysis looks at the final allowance (baseline allowance ± volume driver), the spread of the data and the standard deviation. This allows for a clear comparison of the different approaches with the ability to understand overall accuracy.

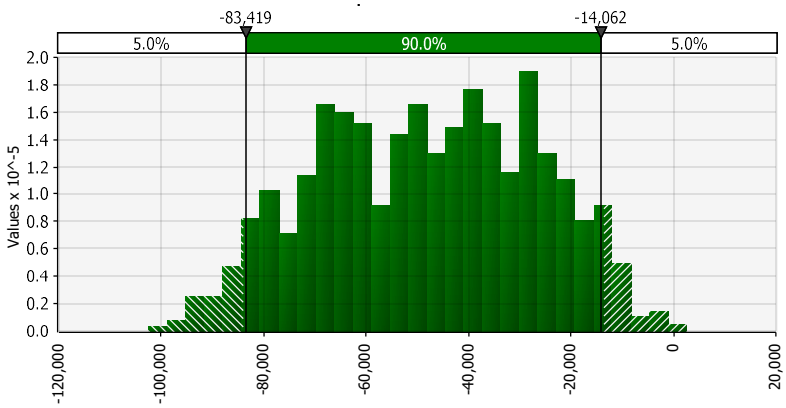


Figure 14: *Approach 1 - Single Rate volume driver modelling results*

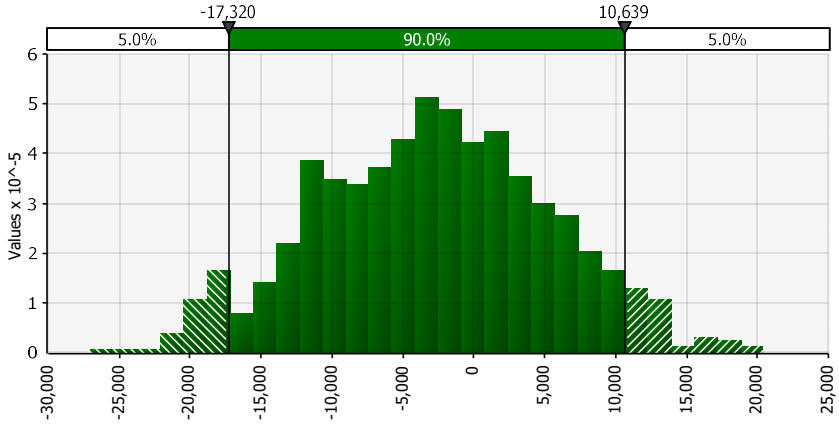


Figure 15: *Approach 2 - Disaggregated volume driver modelling results*

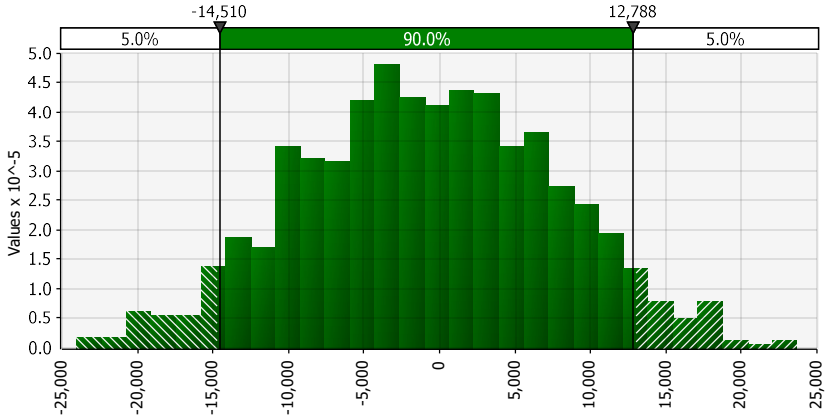


Figure 16: *Approach 3 - Disaggregated Volume Driver with split Shared Use Substation Rate*

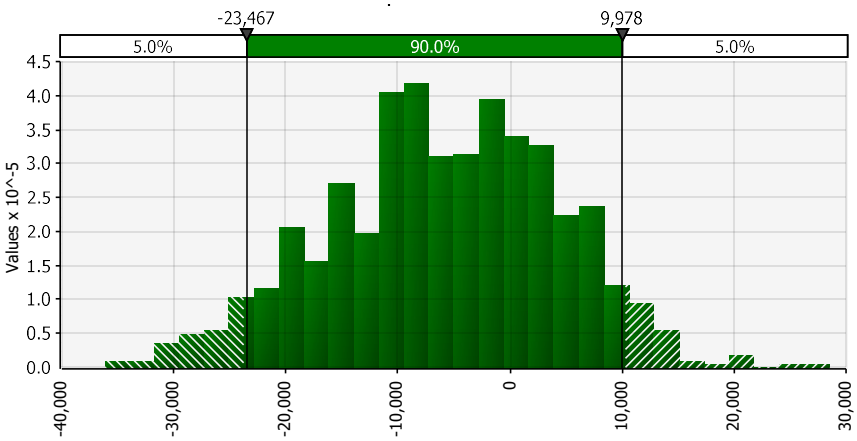


Figure 17: *Approach 4 -* *Disaggregated volume driver using Linear Equations*

Table 1

	1. Single Rate Volume Driver (£k/MW and £k/MVA)	**2. Disaggregated volume driver** (£k/MW and £k/MVA + £k/cct km per voltage/work)	**3. Further Broken down S/S MVA volume driver** (£k/MW and £k/MVA per work type + £k/cct km per voltage/work)	**4. Disaggregated volume driver** (Linear regression - £k)
Minimum (£k)	-60,495	-27,008	-24,016	-36,199
Maximum (£k)	2,634	20,431	23,695	28,485
Average (£k)	-47,967	-2,869	784	-5,905
Std Deviation (£k)	21,448	8,195	8,461	10,245

Analysis shows that using the same approach as applied in RIIO-T1 with a single volume driver rate to cover all works would not accurately reflect project cost. As reflected in a large spread of data with a much larger minimum and maximum allowance and a high standard deviation of £21,448k. The distribution and average result of -£47,967k also suggests that there is a higher likelihood of significant under spend which could come at the cost to SPT and the consumer.

Accuracy was improved by disaggregating the volume driver into Substation, Overhead Line and Cable components. A disaggregated approach offers a much smaller standard deviation and a more accurate average closer to zero, -£2,869k. This would indicate that having a rate of substation infrastructure and a separate rate for linear assets offers a more cost reflective approach to funding additional outputs.

The third approach looked at further breaking down the volume driver into different rates depending on whether substation work was assigned to a Transformer, a new build site or general substation reinforcement. This volume driver provided a similar standard deviation of results and an average close to zero. Whilst the standard deviation was slightly higher meaning a marginally greater spread of data around the mean, this approach proved to be the most accurate as the average result remained closest to zero. This indicates greater accuracy in results.

The fourth approach would use linear regression to calculate allowances for substation and overhead line components. However, this approach did not prove to be more accurate relative to the added complexity of implementation and reporting. Such an approach also has the risk of adding additional complexity to the future calculation.

Several other options were considered as part of the analysis such as set allowances for substation works based on project type, one overhead line rate to cover all works and further econometric equations. These were discarded as they did not produce more accurate results relative to those analysed above.

1.5 T2 Proposal

Substations

Sole Use

The substation volume driver rate will be linked to the Connection Entry Capacity of the Generator i.e. its MW output. This rate will fund all H1 infrastructure works related to the connection of the generator.

It is proposed to utilise a rate of **£14k/MW** to fund the substation component of all uncertain projects. This rate has been calculated using all data points excluding outliers. Outliers were deemed as those more than double the average rate and OFTOs. For outliers that meet this criteria, these projects would require a reopener.

Shared Use

The shared use mechanism will deviate from the existing modular building block approach. It is proposed to now have shared use infrastructure funded similarly to sole use. Substation works would be funded through a £/MVA rate that represent the three main types of work,

- **£44k/MVA** for new substation builds/extensions. This rate will be used when building a new substation or extending an existing site. This rate will cover all works including land purchase and all assets included as part of the shared use infrastructure including transformers. The MVA will be linked to the transformer rating, or in the absence of a transformer, the circuit capacity connecting into the substation.
- **£32k/MVA** for Transformer works. This rate will be used for works involving installing new or replacing existing Transformers. This rate will be used if the Transformer is being installed and the works do not involve a new site or physical extension of a compound. All assets and works required in the substation will be funded via this approach.
- **£14k/MVA** for general substation works. All remaining types of substation works will be covered by a general substation rate. These works include isolator and circuit breaker upratings. Normally, these works are of smaller value compared with a new build or transformer project

Example: Project A – Works involve the creation of a switching station at a new site with two 132kV isolators and a 132kV circuit breaker. MVA created will be linked to the capacity of the connecting overhead line circuit as this will be the maximum capacity the station will be built for. This capacity will then be multiplied by £44k/MVA to provide the allowance.

Overhead Lines

For T2 it is proposed to fund overhead line circuits through a £ per circuit kilometre volume driver. This will further be split between 132kV wood poles, 132kV tower, 132kV reconductor and 275kV and above overhead line works. These rates will be used for both sole and shared use infrastructure.

132kV New Build – Wood Pole circuits

Volume driver will be set at £613k per circuit kilometre. This rate was calculated using the full data set for sole and shared use infrastructure. There were no significant outliers therefore £613k represents the average of all schemes. This rate will be used for all conductor types including HTLS.

132kV New Build – Tower circuits

Whilst we do not expect to be using this rate extensively there remains the possibility of T2 projects requiring an new build tower line. This rate will ensure there is no risk of needing to use a rate formed using wood pole data to fund a tower line which is substantially more expensive. It is proposed to utilise a rate of £800k per circuit kilometre.

Example: To connect two wind farms to an existing substation a shared 10km twin circuit L7 tower line will be built. Allowance will be calculated by multiplying volume driver, £800k, by 20km (10km x 2 for twin circuit line). This will give an overall allowance of £16m.

132kV Re-conductoring

Many shared use infrastructure projects require lines to be re-conductored to provide additional capacity as an alternative to building a new line with greater capacity. This is a cheaper approach and therefor the decision was made to allow this its own rate rather than combining with the new build volume driver. This rate will be set at £210k per circuit kilometre. This rate will be used for all conductor sizes at 132kV.

275kV+ Overhead Line works

There are currently little contracted projects requiring new 275kV and above overhead line works, all subject to uncertainty and these tend to be greater than £25m. Therefore, it is proposed to use the Net Zero reopener to fund any project requiring 275kV and above overhead line works. For any short overhead lines at 275 or 400kV, which are below the materiality threshold, these will require to be considered separately and may use the 132kV tower line rate but further discussion is required on these.

Cable

Cable rates to be utlised in T2 are still to be determined. As discussed due to the small data set it was not deemed appropriate to use this to inform a rate especially as there are several different variations of cable sizes and types. It is proposed to work with the other TOs create an efficient schedule of rates that will fund different cable sizes and ratings for all voltages.

Outliers

Outliers will be treated via the Net Zero Reopener approach which will be a yearly reopener. For more information on Net Zero Reopener see Section 7. There will be set criteria to define what an outlier project is:

- Project unit rate is more than double the associated volume driver and the value is more than £25m
- 275kV and 400kV OHL works with a value of more than £25m
- Project involves the connection of an OFTO – for the known OFTO projects, these are in the range of £6-10m therefore are below the £25m threshold but bespoke in nature due to the role of the OFTOs works.

These drivers should be reflective of the efficient costs we, as the TO, would expect to incur – which from our experience in RIIO-T1, the volume drivers did not reflect. A volume driver that funds the costs associated with the increased capacity/output of the substations as well as the cost of new linear assets (km of OHL) provides a more accurate funding arrangement. This is confirmed through modelling and analysis which sought to understand which volume driver approach provided the most accurate final T2 allowance relative to forecasted costs whilst also managing the complexity of the mechanism.

We do not believe that a full reopener is appropriate because (as discussed above) a reopener mechanism would inevitably result in a delay to each relevant project (as SPT would be required to wait until funding is confirmed by Ofgem) which, in addition to the increased costs of administering such a process, could threaten the economic viability of the underlying projects. By only having a reopener for outlier projects then the majority of projects can continue to be progressed as normal. It was deemed appropriate to allow these outlier projects to be subject to the net-zero reopener as they involve complex and bespoke infrastructure and are generally more expensive than standard connection projects representing greater risk to consumers and SPT if suitable funding is not in place.

Output will be based on Transmission Entry Capacity, additional capacity created and length of circuits required for connection. Although this is more complex than the existing arrangement these outputs are already reported through the existing RRP process.

The mechanism will also include a 1% of Gross Asset Value opex adjustment for the remainder of the price control period to account for the increased O&M costs associated with the new site. This is consistent with RIIO-T1.

1.6 Materiality of issue

An additional 4GW of contracted projects, above the baseline level of generation, are committed to by customers. The value of all these projects amounts to £615m in the RIIO-T2 period. These projects are highly uncertain but if all were to progress then the mechanism would be required to fund an additional £506m of SPT investment. Other projects are likely to contract before the RIIO-T2 period commences and further projects during RIIO-T2. Some of these projects will not go ahead due to a variety of reasons including rejected planning consent, inadequate funding and lack of subsidies.

The number of applications and the volume of generation contracted to the SPT network is ultimately outside of our control, but we have a licence obligation to offer every customer a connection. Every application is considered through the same process and we progress each design in an efficient, economic and timely manner as per our Licence Conditions.

1.7 Frequency and probability of issue over the price control period

SPT T2 baseline focuses on a smaller number of high probability projects compared with T1. This will connect 900MW of new generation to the SPT network. It is the expectation that this mechanism will be used extensively over the T2 period to aid in the connection of increased levels of generation as highlighted in the previous section.

The mechanism will be required for additional generation which is connected to the network and network capacity which is created above the agreed baseline allowance. In the event that the baseline of generation is not achieved, revenue allowances would be returned at the same rate, providing a symmetrical mechanism which is of lower risk to both customers and companies.

1.8 Management of drawbacks

One of the main sensitivities around the volume driver approach is the treatment of outliers. These can greatly skew results and lead to excessive over/under performance. To mitigate this, justified outlier projects will be funded through the net zero reopener. The definition of outliers is detailed above, and this approach allows this small number of projects to be considered by Ofgem in more detail due to their atypical costs and nature. This approach will require additional intervention on Ofgem's part, but due to the small number and high cost sensitivity, we believe that this is justified.

A volume driver uses an average rate to cover the costs therefore projects will over/under perform and it is accepted that as a portfolio this will balance out as shown in the Monte Carlo analysis above. Alternative approaches would require greater intervention and administration from Ofgem which we do not think is appropriate.

All expenditure in this area, both baseline and uncertainty mechanism would be subject to the Totex Incentive Mechanism which would ensure an incentive to minimise costs and share the benefits with consumers, while any overspend would be partly funded by SPT.

1.9 Lessons learned from RIIO-T1

The volume driver used in RIIO-T1 differed between each TO.

For sole use connections, the driver didn't reflect the varying amounts of overhead lines required to serve remote sites and was only based on the generation capacity. Therefore, if a generator connected adjacent to existing infrastructure, the allowance was the same as if it were 50km from the closest infrastructure – despite the costs being significantly higher for the latter case. Furthermore, high cost "outlier" projects were funded the same way as other projects leading to under-recovery even though the costs incurred by the TO were efficient.

In T1 we are forecasted to connect 900MW less than anticipated because the SPT baseline was mandated to be in line the "Gone Green" future energy scenario. The volume driver is being be used to adjust revenues in line with the outputs delivered.

For shared use infrastructure, a unit cost allowance was created for a suite of different assets. Over the course of RIIO-T1, we found that other solutions – which were not defined in the unit cost allowance – offered the most economic and efficient

approach, but as they were not specified at the beginning of the price control, no allowance was provided meaning the efficient expenditure was not remunerated. In RIIO-T2 it is important for customers that similar opportunities to use more efficient technology are taken into account, and it is fair and reasonable that these are remunerated.

Arrangements for T1 projects that carry over and deliver an associated output in T2 were not adequately covered at the beginning of T1 when identifying required mechanisms for the price review period. It is important that such arbitrary cliff edge effects do not work to customers' detriment.

Already there are several generation projects contracted for the T3 period that may require funding in T2 to begin pre-construction or delivery. A mechanism will be required to ensure funding is in place to allow these projects to progress, especially if SPT have a legal obligation to deliver the project by the contracted date.

There are several options currently under consideration to deal with this issue, including:

- Output occurring in next price control forms part of baseline and any spend already incurred to be “trued up” at the end of original price control
- Funding already in place from uncertainty mechanism/baseline and output will not be a price control deliverable for next price control period - it will be associated with original price control

This is not specific to generation connections and would be applicable to all load investment areas, where required.

1.10 Further work

The profile of allowance provided via volume drivers is still to be reviewed to ensure adequate funding is available for the work required at different stages. In RIIO-T1, all three TOs had a different mechanism to reflect the value of work done and how this was accounted for on projects that spanned price review periods. We propose a percentage of the total allowance to be provided each year to ensure funding is made available as the project progresses. This percentage will be based on a standard project expenditure profile.

The agreed allowances for cable costs will also require to be finalised. We propose to use the same schedule of updated rates as NGET in RIIO-T1 and will work with the other TOs to agree this.

2.0 DEMAND CONNECTIONS

2.1 Issue that the mechanism addresses

Similar to generation connections, new demand connections can emerge through the course of a price review which were not foreseen at the time of the plan being agreed. A number of known projects are included in the baseline plan based on consultation with stakeholders such as SP Distribution and Network Rail – see BPDT B0.7 and B4.2a for a full list of all demand related projects included in our baseline plan.

However, others may continue to emerge which require funding, for example other large demand customers such as data centres, heavy industry or large scale EV charging points may also require a transmission demand connection as well as potentially other modifications for SP Distribution. The scope, output timing and cost are unknown for any such project which may emerge. An uncertainty mechanism is therefore required to ensure that consumers don't pay for work that is not required and to ensure that adequate funding can be accessed for any future projects.

2.2 Justification for the mechanism

An ex-ante forecast of demand projects has been made based on applications received and detailed discussions with SP Distribution and Network Rail. In total, 24 demand projects have been included in the T2 Baseline totalling £116.2m of

expenditure. Full details of this are included on page 83-84 of the business plan as well as the relevant engineering justification papers. However, a substantial part of this expenditure is funded by the connecting customer through either capital contribution or annual charges.

A mechanism is required which will allow efficient costs that require to be incurred by SPT to facilitate further projects as required through the course of RIIO-T2. These can emerge at any time, require progression in relatively short timescales and are driven by customer requirements.

No such mechanism was included for SPT in RIIO-T1 which resulted in SPT receiving no allowance, despite some of these projects materialising.

2.3 Ownership of associated risk

The main risk that this mechanism addresses is that additional, or fewer, connections materialise than anticipated. This mechanism provides the means of adjusting our allowed revenue accordingly. The proposed allowances are based on data from various projects to provide as a broad a set of data points as possible to ensure a revenue adjustment is fair and reflective of the costs that could be expected to be incurred. The mean values have been used to provide an equal risk distribution between SPT and customers. Any over or underspend will also be subject to the Totex Incentive Mechanism.

The risk of abortive costs is borne by the connecting party in a similar approach to generation connections. This provides additional protection to end consumers from bearing costs of projects which are not completed.

In the event that the baseline value is not achieved, revenue allowances would be adjusted down at the same rate, providing a symmetrical mechanism which is of lower risk to both customers and companies.

2.4 Type and description of mechanism

A volume driver is proposed which would allow us to recover revenue in line with demand projects progressing. This driver should be reflective of the costs that a TO would efficiently expect to incur. A demand volume driver will operate in a similar approach to generation connections that funds the costs associated with the increased capacity of the substations as well as the cost of new linear assets. This would be through the same £/MVA rate for substation works to build additional capacity and a £/cct km for circuits to fund any H1 shared use infrastructure. This would similarly apply to cable works funded via the proposed schedule of rates and which would be split by voltage and new build/uprating. Overhead line rates have been taken from generation connection as there is only a small data set for T2 Demand projects with overhead lines. Creating additional capacity at a substation involves the same assets regardless if the driver is demand or generation with the rates being well justified based on current portfolio of connection projects. Having the same volume driver allows for consistency in each area and simplifies the mechanism.

The primary difference between the demand and generation volume driver would be in the funding of H1 sole use infrastructure. For demand connections it is proposed to utilise a set allowance of £117k per bay for any sole use substation work required.

Project	A1 £m	H1 £m	Number of Bays
GSP Newarthill Fault Level Mitigation - Output	£ 8.49	£ 0.14	1
GSP Kilmarnock Town Fault Level Mitigation - Output	£ 7.31	£ 0.14	1
GSP Charlotte Street 275/33/33 New SGT1 - Output	£ 4.06	£ 0.07	1
GSP Port Dundas Fault Level Mitigation - Output	£ 5.81	£ 0.11	1
GSP Westfield Fault Level Mitigation - Output	£ 5.15	£ 0.08	1
GSP Strahaven Fault Level Mitigation - Output	£ 3.61	£ 0.07	1
GSP Lesmahagow New GSP - Output	£ 4.64	£ 10.63	2
GSP Moffat New GSP - Output	£ 2.98	£ 0.28	1
GSP Redhouse Capacity Upgrade - Output	£ 2.81	£ 0.05	1
Network Rail Marshall Meadows Capacity Increase - Output	£ 1.96	£ 9.96	2
GSP West George Street Fault Level Mitigation - Output	£ 5.86	£ 0.11	1

Number of Projects with H1 costs	11
Outliers	2
Total H1 Cost. £m	21.635
Total H1 Cost £m (outliers removed)	1.049
Average Cost £m (outliers removed)	0.117

This figure is based on our current portfolio of Demand projects, shown above, and represents the average (H1) sole use infrastructure cost per bay. Lesmahagow and Marshall Meadows were removed from the analysis as they were deemed to be atypical outliers due to their high cost and large scope of works.

Overhead line and cable rates will be consistent with generation volume driver.

2.5 Materiality of issue

Our baseline includes £116m of expenditure. Network Rail have identified the potential for an additional six connections for rail electrification works but these sites are still being finalised. The estimated value would be up to £40m of additional expenditure that would require to be funded via uncertainty mechanism. We have no further details on these projects such as a pre-application request therefore the details for uncertain projects are not reflected in our BPDTs.

2.6 Frequency and probability of issue over the price control period

The mechanism will be required for demand connections which are connected to the network above the agreed baseline allowance. We have worked extensively with SP Distribution and Network Rail and only included projects with a high probability, so the use of this mechanism should be limited. Connections can materialise at any time however historically have been limited, therefore it is difficult to estimate the probability or frequency with which this mechanism may be used.

2.7 Management of drawbacks

To ensure this mechanism works symmetrically and provides a means of adjusting revenues should a project not materialise, each scheme will be set as a price control deliverable. With justification a scheme can be removed and replaced with one of similar scope and value. If a project (or equivalent) has not been successfully delivered by the end of the period this allowance will be under recovered.

Additionally, we propose that the revenue profiling of demand connections aligns with generation connection projects for consistency.

2.8 Further work

As with generation connections the profile of allowance provided via volume drivers is still to be reviewed to ensure adequate funding is available for the work required at different stages. The percentage split of costs to be made available each year will be consistent for all connection projects, both demand and generation.

3.0 MAJOR BOUNDARY UPGRADES - STRATEGIC WIDER WORKS

Ofgem are currently undertaking a review of this mechanism, with a proposal that the title is modified from Strategic Wider Works to Large Onshore Transmission Investment (LOTI). This section outlines some of the principles which we believe need to be considered as part of this review process.

3.1 Issue that the mechanism addresses

Major projects which increase the capacity to transfer power across Great Britain have a high capital cost and a number of other interdependencies. Additionally, many of these projects may extend beyond the scope of only one TO. A consistent approach across TOs is required as some of these projects, particularly for SPT, will involve other TOs to increase the cross-boundary capacity. SWW was defined as being for the consideration of cross-boundary projects but going forward this should not exclusively be for this purpose, and also include other wider works which may not provide an incremental increase to a boundary capability.

3.2 Justification for the mechanism

A mechanism is required which will evaluate additional projects separately to the main price review as the need case and proposed solutions evolve. At the time of submitting the RIIO-T2 business plan, some uncertainties around these projects exist which prevent them from being included such as the interaction with other projects, the preferred system solution and accurate costs.

The existing SWW mechanism operates as a reopener to allow OFGEM to assess the specific costs and risks that each project presents once it is well developed and has greater certainty of the associated costs and benefits. OFGEM consider the full economic impact of the project, including constraint costs which are calculated by the ESO across different scenarios and undertake a more rigorous analysis of solutions proposed.

These projects are generally of high value >£100m with uncertain need cases as well as uncertain cost estimates. As a result of this, a volume driver is difficult to create and would carry with it high risk of overcharging consumers for under-recovery of efficiently incurred costs to TOs.

3.3 Ownership of associated risk

Due to the level of uncertainty of some projects in this category, it may not be reasonable for these to be considered as part of the main regulatory price review. Doing so may place additional risk on consumers and companies due to the number of associated uncertainties.

There are risks on TOs with the existing Strategic Wider Works process that projects at the initial needs case stage are above the £100m threshold end up falling below this value as costs are refined. In this case the project, regardless of need, consumer and network benefits, may not be funded through this process. For this reason, we are also proposing a separate mechanism to address projects which fall into this category; please see the Net zero transition reopener for further details.

The extensive review process which is taken to projects of this nature include an evaluation of the initial needs case, the final needs case, and a project assessment of the solution costs ensures that investments are only made when they are of benefit to consumers and the costs are well evidenced. Not progressing these projects or their deferral to the subsequent price review is likely to result in significant consumer detriment as it may lead to additional balancing costs to the ESO which are ultimately borne by consumers.

3.4 Type and description of mechanism

This mechanism is to primarily address wider works projects with a value in excess of £100m and are subject to uncertainty at the time of submitting the RIIO-T2 business plan. SPT RIIO-T1 licence definition of wider works is "*transmission reinforcement works that are designed to reinforce or extend the National Electricity Transmission System which may*

include works to attain compliance with the terms of the National Electricity System Security and Quality of Supply Standard (or such other standard of planning and operation as the Authority may approve from time to time and with which the licensee may be required to comply in accordance with standard condition D3 (Transmission system security standard and quality of service))."

This mechanism would allow for within period revenue adjustment for projects with a threshold value of more than £100m and which cannot be clearly defined at the time of publishing their RIIO-T2 business plans. The revenue adjustment also includes an Opex adjustment equal to 1% of the value of the additional wider works output. Strategic wider works are currently specified in Special Condition 6I of the SPT licence. We are proposing that the principles of the current process are maintained for projects above the threshold with some refinements to the timing of the different steps and a review to reduce the overall timescales.

3.5 Materiality of issue

For SPT, only one known project is currently identified for funding through this mechanism, the SPT-NGET Eastern Link subsea cable. This project has an estimated value of between £1.7-2.6Bn depending on the technology utilised and exact route that the cable takes. This project is detailed in BPDT B4.9 SWW Memo using the current estimate of £1.7bn. Further details of this project and its interaction with other baseline projects is included in Annex 4: Strategic investments.

The NOA process is reviewed annually and other projects may emerge over the course of RIIO-T2 but the cost and scope of these is not known at the time of submitting the RIIO-T2 business plan.

3.6 Frequency and probability of issue over the price control period

Due to the nature and scale of these projects, there are several uncertainties including the scope of the project and accurate cost details which cannot be identified in advance of RIIO-T2 starting. The need case for the eastern link is high therefore we deem the use of this mechanism to be highly likely and the submission of the initial needs case is expected in early 2020. Any other project would be taken to OFGEM within period for assessment when more information is known.

We have only identified one project which would utilise this mechanism and consider that only one or two others may emerge over the course of RIIO-T2 depending on how the energy landscape evolves.

3.7 Management of Drawbacks

This mechanism has been used a number of times by SHETL and National Grid. SPT developed one project under this framework, but as it was less than £100m when the final assessment was completed, it was no longer eligible. SPT had no other means of funding as a result of this. For this reason, a separate approach is proposed for new projects which emerge that are of less than £100m in value and have no other funding mechanism.

Experience has also shown that the current process can be bureaucratic with many stage gates and is resource intensive for the TOs and Ofgem alike. The overall process should be reviewed in light of the experiences of both TO's and Ofgem's part of the review process for LOTI. Naturally any change must ensure that Ofgem has the required information to fully assess any proposals

3.8 Further work

Ofgem have indicated that engagement with TOs will continue following the submission of the RIO-T2 business plan. We will continue to support this work as required.

4.0 NET ZERO OPERABILITY CHANGES

4.1 Issue that the mechanism addresses

New operability issues are likely to emerge in RIIO-T2 such as a result of a changing energy landscape. These may be in the form of high/low voltage, harmonic non-compliance or other characteristics of the electricity transmission system which are non-compliant with the relevant standards. These will emerge due to the changes that the network is undergoing from greater volumes of renewable generation connecting to the network, the closure of thermal generation and changing demand profiles as a result of end user behaviour. All of these factors are driven by the changes in support of the government ambition to reduce the emission of greenhouse gases. These changes may also require new arrangements to actively manage the output of generation by the ESO to ensure the operability of the network.

Extensive modelling has been undertaken to ensure our baseline business plan has the necessary solutions based on the scope set out in the Future energy scenarios; however, these cannot cover every eventuality. We are confident that the range of uncertainty that the Future Energy Scenarios presents can generally be accommodated by our plan. The new focus on a Net Zero target however goes beyond the existing FES and may create issues on the network that cannot currently be foreseen. To help support the ESO in their ambition to have an electricity system that can operate carbon free in 2025, we expect other requirements may emerge that need to be accommodated.

This mechanism is focussed on addressing operability issues on the network which may create an impediment to the ESOs efficient operation and would result in SPT failing to comply with the relevant network standards.

4.2 Justification for the mechanism

The uncertainty pertaining to the operability of the network is primarily as a result of changes by end users connected to the network. Some of these users may be in regions connected by other TOs, but still have an impact on the operation of the SP Transmission network. This mechanism provides several known solutions to some of the issues that we consider may arise. This suite of solutions cover what could be reasonably foreseen and minimises the requirement for Ofgem intervention due to a clear trigger for the solutions to be deployed, and efficient unit costs being agreed as part of the business plan review process.

The need for these solutions to be deployed would be triggered by the ESO submitting a STP planning request for such a modification to take place or the non-compliance with the relevant engineering standards such as Engineering Recommendation G5/4 relating to harmonic compliance. Historically, these are less than £5m in value and the need may emerge in a relatively short timeframe. An example of this was Planning Request NGET 2014/SPTL001 which required the creation of a new load management scheme with multiple generators in a seven-month period. In this instance, there were no funding mechanisms in place to cover costs which were incurred and could not have been reasonably foreseen. Through informal discussions with the ESO, it has been indicated that as generation continues to connect, and potential network constraints grow, the need to deploy such an approach will increase. The exact volume and location of such arrangements cannot be forecast at this time.

This mechanism provides a unit cost allowance for a range of solutions, based on the efficient rate, and avoids the need for triggering the Net Zero Transition Reopener with Ofgem for standard solutions with a clear driver and costs which are assessed as efficient.

Uncertainty mechanisms for this purpose were not included by SPT in RIIO-T1 yet SPT were exposed to costs as a result of some of these changes which were unfunded.

Specific operability issues have been identified as likely to arise in T2 that this mechanism would support include:

Managing high transmission system voltages

A number of factors have contributed to difficulties in managing high transmission system voltages under lightly loaded network conditions:

- The closure of large synchronous generating plant.

- The increased use of cables, which have a significantly higher capacitance than overhead line for the same circuit length.
- Changing demand characteristics. In general, transmission system reactive power demand is reducing.
- Increased volumes of embedded generation have led to a reduction in the transmission system load at the time of minimum demand

In 2014 the joint Northern England and Scottish Operability Study (NESOS) recommended the installation of 1020Mvar of shunt reactive compensation to contain high voltages in Northern England and Scotland. The study identified 420Mvar of additional shunt compensation for the SPT area, all of which is expected to be delivered by the end of the RIIO-T1 period. 515Mar of compensation is included in the RIIO-T2 baseline plan. Due to the potential level of generation changes that may occur, we view it as a low probability, but additional compensation may be required.

Preventing voltage harmonics

Harmonic resonance in some parts of the 132kV network is leading to amplification of background harmonics to levels above the Engineering Recommendation G5/4 planning levels. This issue can be mitigated by the installation of standardised harmonic filters to provide a coordinated and efficient solution. Six harmonic filters are included in our RIIO-T2 baseline plan to identify known issues. The provision of a means of addressing any further non-compliance is required if the network changes to an extent beyond the scenarios which we have planned for.

Preparing for Load Management scheme installation requests by ESO

System to generator load management or control of output in operational timescales are typically used by the ESO to increase boundary transfers in operational timescales by managing or tripping generators on the exporting side of a boundary in the event of a critical fault. This reduces the power transfer after the fault, preventing circuit overloading or transient instability[1].

SPT is unable to predict the number of such schemes that may be required or the generator(s) that will be offering a load management service. These are identified and requested by the ESO through a SPT planning request as the need emerges. We have not been notified of any additional requirements in RIIO-T2 by the ESO as we have developed our plan.

Supporting system strength

In our draft plans, we identified the need for synchronous compensation to mitigate the loss of system strength and inertia, and to provide vital system support in the unlikely event of a black start. We still believe that this plant is essential for economic and stable operation of the network as power stations with synchronous generators close. As the ESO continues to progress with its Stability Pathfinder project (https://www.nationalgrideso.com/publications/network-options-assessment-noa/network-development-roadmap), the outcome of this exercise could have a significant impact on the location and number of synchronous compensators that are required in our network area. We have therefore removed the synchronous compensation from our baseline plan to allow the competitive process that the ESO is undertaking to operate. We have identified three synchronous compensation projects that align with their requirements and provided the details of these to the ESO for their consideration as part of the early competition process they are undertaking.

4.3 Ownership of associated risks

There is a risk of non-compliance with SPT licence obligations if these operability issues cannot be mitigated. An uncertainty mechanism provides an allowance to build solutions when required to maintain network security. The costs proposed for this mechanism are robustly supported by a range of evidence to inform the allowances.

Should we not be able to progress these projects in a timely manner, there will be increased risk and cost exposure to the ESO and ultimately network users through increased BSUoS for additional services that arise by these issues. Having this mechanism reduces this risk by allowing us to implement cost effective solutions to negate this cost. For example, if the

[1] Note that load management schemes differ from active network management schemes which are designed in network planning timescales and used to manage local network constraints.

stability pathfinder identifies synchronous compensation to be the most effective solution, any delay to their installation would require the ESO to pay third parties for services which will be passed through to network users.

Any under or over spend against the volume drivers will be subject to the Totex Incentive Mechanism in the same way that baseline allowances are to further help to balance the risk between consumers and SPT.

4.4 Type and description of mechanism

As outlined above, there are several network issues that may require mitigation during the RIIO-T2 price control period. While the solutions are known, the locations and timings of their installation are uncertain and hence an allowed unit cost for a range of solutions is proposed. The use of the solutions listed below would be contingent on a STP planning request being received from the ESO. The ESO would only issue such a request to a TO once other viable options have been explored including non-build approaches. These alternatives will include the outcomes of the Pathfinder projects which the ESO is currently undertaking with support from TOs and other network operators. This approach would provide a level of separate scrutiny to the progression of any scheme under this mechanism.

Shunt Reactor

The application of shunt reactors is a well-established solution to managing system voltage. For SPT, the most efficient and standard solution is a 60MVAr reactor. Engineering Justification Paper SPT200124/5 provides an exhaustive analysis of the alternative options to this solution including a CBA. The deployment of this as a solution would only be used after non-build options have been considered as is being explored by the ESO in their Voltage pathfinder project in the Merseyside region. A total expenditure of £9.58m for 4x 60MVAr shunt reactors is proposed in the RIIO-T2 therefore we propose a unit cost of £2.395m per additional unit that is required. A summary of the costs to substantiate this unit cost are included in Appendix B.

The need for this solution would be triggered through the receipt of a STC planning request.

Harmonic Filter

The issue of harmonic resonance can be mitigated by the installation of standardised 20Mvar damped (C-type) harmonic filters at key substations. An ex-ante allowance to install six harmonic filters is included in our baseline plan (Scheme reference SPT200126). Any works which are additional to those accounted for in the baseline plan will be funded through the use of a volume driver based on a unit cost allowance per filter - £4m. This allowance is based on the average cost of the works per site in the RIIO-T2 business plan. See BPDT B4.2a, projects SPT200126 for further cost information and associated outputs. Whilst asset costs will remain largely consistent, it is the location that will be the primary driver of additional costs. Baseline works cover a variety of locations and therefore were deemed an appropriate data set to provide costs for a typical project. A summary of the costs to substantiate this unit cost are included in Appendix B.

The need for this solution would be triggered by a study result and supporting evidence against the relevant engineering standard for harmonic compliance.

Operational Load Management Schemes

Our generation export management scheme (SPT200132/3) provides a strategic network management service across South West Scotland. The exact cost per site will vary depending on the individual sites, however across RIIO-T1 we have installed a number of these which have been used as the basis of the proposed unit costs.

It is proposed for this mechanism to operate on a unit cost basis split between:

- Installing/extending existing scheme at Power Station site – with a unit cost of £144k, and
- Installing new scheme at substation site – with a unit cost of £287k

For example, a new scheme that monitors a circuit between site A and site B and intertrips a power station at site C if either or both ends of the circuit are opened. Two sites and a power station are involved, leading to the scheme cost in the table below.

Scheme Component	Cost
Site A – new	£287,000
Site B – new	£287,000
Power station at site C	£144,000
Total allowance	£718,000

This approach allows for multiple variations of protection requirements to be funded efficiently. Unit costs are based on previously installed schemes with a differential for establishing a scheme at a new substation compared to extending an existing scheme. A summary of the costs from RIIO-T1 to substantiate this unit cost are included in Appendix B.

The need for this solution would be triggered through the receipt of a STC planning request.

Synchronous compensation

We have identified three synchronous compensators which could fulfil the ESO's requirements identified in their RFI which was published in 2019. We have identified the costs associated with these and detailed the costs and broader engineering justification in EJP_SPT_SPT200137-142 in Annex 1. We propose that these are assessed by Ofgem and an agreed allowance for them is established as part of the RIIO-T2 business plan assessment. In a similar way to the uncertainty non-load projects, these would be Price Control Deliverables. The ESO intends to commence a competitive process in 2020 for long term services. We believe it is appropriate for the SPT solutions to be considered as part of this process. These projects would only proceed for this purpose on the basis that they are identified as being the most appropriate solution by the ESO through this process. This approach provides a timelier solution for this issue which the ESO is seeking to address than considering them through the Net Zero Transition Reopener which would not take place until 2023 which would ultimately delay the completion of these units. Considering these this way would also reduce the expense required by Ofgem to consider additional reopeners early in the price review process.

The need for this solution would be triggered through the receipt of a STC planning request.

4.5 Materiality of issue

We currently have £55.7m in our baseline plan for these solutions which has been based on extensive modelling and analysis. These costs are detailed in tables B0.7 and B4.2a. In the RIIO-T2 plan we are proposing to install:

- 515MVArs of reactors and compensation to address voltage non-compliance following the closure in generation and demand profiles. The total value of these schemes is £30.1m. Details provided in Engineering Justification papers SPT200122 (Shunt Compensation Hunterston), SPT200134 (Shunt Compensation Mark Hill), SPT200124 (Shunt Compensation – operability).
- six 132kV harmonic filters have been included in the T2 plan at a cost of £24.2m. Details provided in SPT200126 (Harmonic Filters).

The costs associated with the three Synchronous compensators totals £158m (as per BPDT 5.18). It is unclear until the Stability Pathfinder project has reviewed the various options as to whether all three synchronous compensators will be required. A pre-engineering allowance is included as part of the overall pre-engineering forecast (SPT200136) to allow these projects to progress with initial development before the unit cost allowance associated with these projects is triggered. We expect that following phase 1 and 2 of the stability pathfinder project, this process is likely to evolve which may require further sites to be developed. Full details of the stability pathfinder project can be found at https://www.nationalgrideso.com/publications/network-options-assessment-noa/network-development-roadmap .

The costs associated with these solutions have higher confidence than those we expect will proceed under the Net Zero Transition Reopener and a clearer trigger. The consumer benefit is likely to be substantial as it will mitigate costs the ESO and consumer may otherwise face for system constraint payments. By making this mechanism a mechanistic unit cost allowance, the level of intervention required by Ofgem is significantly reduced to reflect the lower cost of such an uncertainty.

The approach is relatively simplified whilst still ensuring additional allowances can be accessed if and when required. The unit cost allowance provides a clear approach to deploying additional schemes that is based on evidence from an independent source (the ESO), and the flexibility to allow schemes to be progressed at additional sites as necessary.

4.6 Frequency and probability of issue over the price control period

This mechanism would only be triggered by the ESO submitting a STP planning request for such a modification to take place or the non-compliance with the relevant engineering standards such as Engineering Recommendation G5/4 relating to harmonic compliance. Non-build commercial solutions would also be considered by the ESO before this mechanism would be utilised. We have seen in RIIO-T1 that the need for these can emerge relatively quickly and can carry significant savings for the ESO once deployed.

A number of justified voltage support and harmonic filters schemes are already included in our baseline plan. Additional installations are only expected to be required should there be a significant change beyond what we have planned for through the energy scenarios. The application of the Synchronous compensators would only be as a result of the ESO's analysis of the stability pathfinder work.

Without these, it is likely that the ESO would face additional operational costs in managing the network, the costs of which would be borne by all customers.

4.7 Management of Drawbacks

The proposed approach utilises a fixed unit cost which provides its own risks as costs incurred may be greater or less than anticipated. A data set reflecting current cost forecasts has been used to inform rates so that they are as accurate and efficient as possible. These costs are drawn from the same data set and level of justification as the baseline plan therefore we view the risk as being comparable to the wider business plan for both SPT and the consumer.

Without this mechanism, the solutions identified would need to be addressed as part of the Net Zero Transition Reopener which would require greater intervention from Ofgem.

4.8 Further work

No further work is required for this mechanism.

5.0 NET ZERO TRANSITION REOPENER

5.1 Issues that the mechanism addresses

The transition to Net Zero is likely to result in further changes to the demand and generation make-up across Great Britain. We have based our business plan on a range of future energy scenarios (FES2019) which had an upper case of the previous government target of a reduction to GHG emission of 80% by 2050 for Great Britain. The recent move to a requirement of net zero GHG emissions by 2045 for Scotland goes beyond this and the exact implications this may have on the transmission network are not fully understood or modelled. As a result, new projects may emerge to achieve the Net Zero target which are not currently foreseen.

Whilst the strategic Wider Works/LOTI mechanism provides a means of addressing uncertain Load related projects of greater than £100m, and the Net Zero Operability Mechanism provides a range of known solutions to address the operability challenges, this mechanism is to specifically address the gap between these mechanisms that may emerge during the course of the price review and cannot be addressed by a known standard solution with an agreed unit cost. There are four potential sources for such projects:

- Wider works reinforcement projects similar in nature to SWW/LOTI but of lower value. These projects are considered as part of the annual NOA process in its current form. The ESO has indicated that the scope of NOA may evolve in the future to consider other dimensions of the development of the transmission network, the solutions for which we may have to provide. With the NOA process being undertaken annually, it is foreseeable that new projects may emerge over the course of RIIO-T2.

- Efficient anticipatory investment which is not identified at the outset of the price review. In Ofgem's open letter dated the 8th August 2019, it was identified that "*grid capacity augmentation should be somewhat 'future proof', meaning that where upgrades occur, they should be to a size sufficient to ensure no future augmentation at the relevant site would be required prior to 2050*". It is expected that other opportunities for such projects will emerge over the course of the RIIO-T2 period, but the nature and scale of such projects is uncertain. Without a means of funding these, the TO may consequently not have sufficient funding to undertake what is later identified as the more cost-effective solution for customers. This cannot be accommodated in other mechanisms due to the level of uncertainty on the solutions and potential costs.

- Other operability solutions which are not included as part of the proposed suite of solutions identified in the 'Net zero operability mechanism'. These may be unique in nature to address specific issues or the data available to determine a standard unit cost is not available.

- Generation connections which are defined as outliers from the generation connections mechanism. From the analysis identified above, this would apply to projects that are more than double volume driver rates and greater than £25m. Additionally projects with a MW output of greater than 250MW will be included in this reopener.

5.2 Justifications for the mechanism

A number of uncertain load projects with value of less than £100m have been proposed to address the needs the ESO identified through the NOA 5 process.

Wider works projects identified through NOA

The results of the NOA5 process are due to be published in January 2020 which is post the publication of the RIIO-T2 business plan. We expect that further projects will emerge over the course of the price review. These projects are at an early conceptual stage and further engineering is required to consider the costs and engineering programme, as such they are not detailed in our Business Plan data tables. A pre-construction allowance (scheme reference SPT200136) has been included in our baseline plan to progress these projects should it be required to such a point that a reopener application would be made with greater need and cost certainty.

These include:

- **Elvanfoot-Harker Reconductoring (EHRE)** – Increasing the capacity of this 400kV circuit by replacing the conductor on the existing 400kV double circuit overhead line route from Elvanfoot to Harker (ZV total route length 67.29km) on existing towers. Estimated value of £82m.

- **Denny North – Clydesmill – Wishaw 400kV Reinforcement (DWUP)** - Creation of a new 400kV circuit crossing boundary B5 between Denny North, Clydesmill and Wishaw utilising reconfigured existing 275kV double circuits between Longannet and Clydesmill and Easterhouse and Wishaw via Newarthill. Estimated value of £85m

- **East Coast Onshore 400kV Phase 2 Reinforcement (TKUP)** - Upgrading existing 275kV circuits between Tealing (in SHET's area) and SPT's Longannet via Glenrothes, Westfield and Mosmorran. To be completed post ECU2 and ECUP and include the installation of new transformers at affected sites. This project is associated with the uncertain Non-Load projects which have been identified and tie in with Westfield and Longannet switchgear replacements. Estimated value of £52m

- **Windyhill-Lambhill-Denny North 400kV reinforcement (DLUP)** - Reprofiling of Windyhill-Lambhill-Denny North 275kV circuit (which will be fully established under WLTI) to 400kV operation, via the installation of new transformers at Windyhill and Lambhill. Creates a new 400kV corridor, allowing increased access to existing Western HVDC link. Estimated value £93m.

Anticipatory investment

As new generators apply for connection to the network, it is foreseeable that future requirements for anticipatory investment may materialise. These are not catered for through the generation or demand connections uncertainty mechanism. The justification for major anticipatory investment is also more subjective and may interact with projects that are identified through the NOA process – however with this being an iterative and annual process, it is clear that where future need is identified (even on a marginal basis), that the needs case is highly reliant on a forecast and will carry risk.

Where such projects are proposed, we have identified potential challenges under the present regulatory regime which require further consideration; specifically, the impact on generators liability and securities, and on consumer bills for such projects. It is not presently clear how such investment for the future could be measured as being efficient and presents a financing risk with respect to the potential for disallowed costs. We believe that further and considerable work is required to (i) understand how these barriers can be addressed to minimise the impact on future connecting customers (ii) ensure that all customers pay fairly and proportionately for the investment made and (iii) that the impact on present consumers bills are mitigated but are understood as being considered to be efficient investment based on a forecast at a specific moment in time..

Other operability solutions

We have proposed known operability solutions as part of the Net Zero Operability Changes mechanism, however these only provide a small range of solutions which can be defined. Depending on the progress of the various pathfinder projects and changes in the electricity network, other solutions may emerge which cannot currently be predicted. We view this as having a low probability however if the need did emerge and reached the materiality threshold then it is likely to result in a significant cost to consumers through additional services that the ESO would need to fund. On this basis we have proposed this as one of the justifications in the event that something does emerge.

Generation connection outliers

As discussed in section 1 connection outliers will be treated via the Net Zero Reopener approach. There will be set criteria to define what an outlier project is:

1. Project unit rate is more than double the associated volume driver and the value is more than £25m, or
2. 275kV and 400kV OHL works with a value of more than £25m, or
3. Project involves the connection of an OFTO or generator greater than 250MW – these are in the range of £6-10m therefore are below the £25m threshold but bespoke in nature due to the role of the OFTOs works. Additionally those with a high MW output will have a significant impact on performance due to their sensitive around volume driver rates..

5.3 Ownership of associated risks

Without this mechanism, we may face significant expenditure to comply with licence obligations as a result of external changes such as generation and demand, both in areas and outside their respective network area. These projects will be driven by the targets to decarbonise the energy system therefore the deferral of these schemes may have a wider societal impact. Without such a mechanism, these projects may result in the ESO incurring higher constraint costs to operate the network which will be borne by consumers. These projects have a high probability of being of material value in the RIIO-T2 period

The inclusion of using this mechanism for anticipatory investment provides additional time for such projects to be justified rather than making high level estimates at the time of the business plan submission.

Due to the level of uncertainty associated with projects identified in this mechanism, a reopener ensures that cost uncertainty is minimised to protect consumers.

5.4 Type and description of the mechanism

An annual reopener window is proposed for projects in this category. The reasons for this frequency are as follows:

- The NOA process takes place on an annual basis therefore new projects can emerge with the same frequency.
- Anticipatory investment may be associated with infrastructure for new connections. We are obliged to connect these customers in a timely manner and as such, new requirements may emerge as part of this which need to be acted on in a timely manner to maximise the opportunity.
- Operability solutions required by the ESO are being considered over the course of 2020 and the success of this will dictate if further solutions are required over the course of the price review. No further details have been provided by the ESO on how this process may operate following the tendering exercise.
- New customer connection projects can emerge at any time. Those that are outliers are generally more complex in nature due to their scale and are likely to require funding to allow them to progress.

A materiality threshold of £25m totex is proposed which is consistent with the High Value Project reopener that is applied to Electricity Distribution Network Operators in RIIO-ED1. The one exception is for OFTO projects which are considered to be new connection outliers. Generally, these are of lesser value that £25m but are unique in nature due to their scale and output that they enable. SPT have two projects which are contracted but uncertain in RIIO-T2. These projects are subject to ongoing changes and a detailed cost estimate and timing cannot be provided as the timing and scale of the projects continues to evolve.

Details of the electricity distribution high value project reopener can be found in the Electricity distribution licence. In a consistent manner with other reopeners, any application would require to have detailed outputs, a needs case, and a statement of costs have been provided and in respect of which there is no other mechanism for the adjustment of allowed expenditure levels. Due to the longer timescale of typical transmission projects, a reopener should be for the approval of the projects costs in its entirety and not only those costs which are incurred in the RIIO-T2 period. Without such an approach, there is a risk that a project is in effect partially approved yet the transmission owner will be required to commit to contracts and costs that extend beyond the price control review period.

5.5 Materiality of issue

The materiality of Net Zero related initiatives is challenging to quantify at this time as the exact steps required to meet this target continue to evolve as we develop this business plan. It is however essential that the price control remains flexible to new requirements identified to facilitate our successful transition towards net zero.

Based on the potential projects identified above, as many as eleven reopeners may be required. All of these projects have values in excess of £25m (except OFTO projects) which is of equal materiality to consumers as the threshold that is applied in electricity distribution.

5.6 Frequency and probability of issue over the price control period

An annual reopener is required for this category due to the short timescale in which new projects may emerge, in particular new connection projects. This would include a reopener in the first year of the price control review, in early 2021. This is necessary as the plans that are submitted are correct as of the end of 2019 and the requirements of the system for these areas of uncertainty are highly likely to have progressed.

Furthermore, given the urgent industry wide support for Committee on Climate Change's recommendations, the likelihood of this uncertainty mechanism being used to enable other net zero related initiatives is relatively high.

5.7 Management of Drawbacks

This approach will require resources and for both Ofgem and TOs to justify the reopener and for Ofgem to evaluate and consult on the outcome. We do not consider other approaches to be appropriate such as a volume driver or unit cost allowance as these are reliant on a clear efficient cost for a given solution, and for all of the projects detailed in this mechanism, both the needs case and potential solutions are uncertain. We do not consider this approach to be unreasonable given the amount of expenditure that may be associated with them.

If these projects are not progressed under RIIO-T2, it is expected that additional costs and risk will be passed on to network users through BSUoS and other system charges associated with managing the constraints of provision of other alternative services.

5.8 Further Work

Further consideration is required on the treatment and arrangements of anticipatory investment. Such an approach may have a consequential impact on future new connections by mitigating costs that they would otherwise pay for or passing greater risk on to consumers. We are supportive of the need for anticipatory investment but are of the view that a consistent framework is required to ensure this takes place with a level playing field.

6.0 UNCERTAIN NON-LOAD PROJECTS

6.1 Issue that the mechanism addresses

We have a number of non-load projects which have significant uncertainties associated with them, such as land purchases, or are interactive with new generation connections which may negate the need for them or change the required solution. The costs for the non-load works are not uncertain but the timing of the intervention is. We don't believe that it is appropriate to include these in our baseline with such high uncertainty at the start of the price control.

6.2 Justification for the mechanism

The need case is specific to the named projects and the timing is the uncertain factor. The mechanism ring-fences the expenditure and generates allowances only when the timing uncertainty is resolved. The projects' costs will be subject to the same level of scrutiny as the baseline programme. Allowances will be generated when there is sufficient certainty over timing.

This mechanism will prevent allowances for uncertain schemes being generated in the baseline and will allow proper scrutiny of the need case. This approach is broadly consistent with the RIIO-T1 licence condition 6H that identified similar projects and treated them in the same way.

6.3 Ownership of associated risks

The inclusion of the projects in an uncertainty mechanism minimises the risks for both consumers and the licensee because the allowances will only be triggered when there is sufficient certainty. By providing the costs and need case of the projects as part of the business plan, they can be assessed by Ofgem in a consistent way with baseline projects to ensure cost efficiency and certainty of need case.

For projects that are not in this mechanism, the TO will accommodate the risks associated with other factors such as delays to planning permission, however these are viewed as having a low probability.

6.4 Type and description of mechanism

We have identified the name, costs and justification for various projects, each of which has individual Price Control Deliverables. As there is a high degree of cost certainty, we propose to agree the costs ex-ante and provide information on progress both by exception and as part of the annual reports.

6.5 Materiality of issue

The costs noted in the business plan total £146M across six schemes. It is likely that around £110M will be triggered by three of the schemes.

The projects are listed in the master data tables (C0.7)[2] but there are no costs or activity volumes in the tables (C2.2a or C2.5) but each scheme is detailed individually in table 5.18. The costs and volumes are noted in the core business plan documents. There are Engineering Justification Papers for each of the relevant schemes which provide the same level of justification as for baseline schemes.

6.6 Frequency and probability of issue over the price control period

We propose to trigger the projects individually to ensure that allowances are only generated for the schemes that have sufficient certainty of timing. We expect that three of the six schemes currently identified have a high probability of being triggered in the period.

6.7 Management of Drawbacks

There are no foreseen drawbacks for consumers caused by the presence of this mechanism. This is broadly consistent with the licence condition 6H which was included in the SPT RIIO-T1 licence.

6.8 Further work

These projects will require assessment by Ofgem as part of the business plan review. These have been submitted as part of the Business Plan submission.

7.0 WHOLE SYSTEM 'COORDINATED ADJUSTMENT MECHANISM'

7.1 Issue that the mechanism addresses

Through the course of RIIO-T2, the optimal approach to address network needs may change between companies across gas and electricity, distribution and transmission. Ofgem have identified the need for an approach to provide a means for protecting consumer interests by supporting the reallocation of project revenues and responsibilities to the network(s) best placed to deliver those projects.

7.2 Justifications for the mechanism

This is a new mechanism for RIIO-T2 and was detailed by Ofgem in their sector specific methodology document. This mechanism will work to improve whole system planning and operation, improve support for new whole system approaches, and ensure the price control is not a barrier to the efficient allocation of projects across networks.

[2] SPNLT2034, SPNLT2099, SPNLT2063, SPNLT20111, SPNLT20112, SPNLT20113

7.3 Ownership of associated risks

Ofgem have identified that further workshops will take place in early 2020 to progress how this mechanism will operate and the management of risks.

7.4 Type and description of the mechanism

Ofgem have identified in the RIIO-2 Sector specific methodology – core document that the mechanism would ideally be triggered by two (or more) cooperating networks, but a single network could also trigger the mechanism if they were able to meet the threshold requirements. Ofgem have also identified the following requirements on network operators:

- provide a sufficient level of specificity of the proposed changes, their impacts, and their estimated costs and benefits on all affected networks' consumers
- provide evidence that the overall value of the project meets a pre-specified threshold. At this stage, we indicate £20m as a rough estimate of a value sufficient to justify the administrative cost. Final figures will be specific to each sector, based on sector specific analysis of projects raised in the Business Plans.
- meet the windows we have established for when the mechanism can be triggered. This will be in years two and four of the 2021 RIIO-2 price controls to allow for integration of the ED-2 Business Planning cycle and to ensure projects with long planning periods are not unnecessarily delayed
- demonstrate that the coordinated solution cannot be delivered through existing regulatory or commercial arrangements, or is substantially more efficient than any other solution
- evidence that the potential solution could not have been proposed through the usual Business Planning processes, potential because of new information which was unforeseeable at the time of Business Planning
- demonstrate that the realignment of revenues and responsibilities does not create excessive distributional issues, and does not contribute to any unreasonable outperformance on other incentives
- where relevant (eg, particularly for TOs) have received and included the advice and opinion of the ESO.

We will continue to support Ofgem in their definition of how this mechanism would operate in practise through further cross sector workshops.

7.5 Materiality of issue

Ofgem have indicated that projects in excess of £20m would be required to trigger this mechanism. This is still to be fully defined. We would like to understand the proposed approach of any adjustment which is required below this threshold or if it is accepted that no adjustment would be made due to the lack of materiality.

7.6 Frequency and probability of issue over the price control period

Initial indications are that this would take the form of a reopener in light of new information emerging and would ideally be triggered by two (or more) cooperating networks. We will continue to work with Ofgem to further define this.

7.7 Management of Drawbacks

This approach does risk complicating the price control review and further definition of this mechanism is required. In Ofgem's sector specific methodology a number of areas that require to be addressed are identified.

7.8 Further work

We will continue to support Ofgem with this work. We are of the view that this mechanism will require to be developed on a cross sector basis for it to be effective.

LEGISLATIVE, POLICY AND STANDARDS UNCERTAINTY

8.0 Issue that the mechanism addresses

A number of new technical standards, regulatory amendments and legislative requirements emerged during RIIO-T1 which SPT was obliged to comply with, without an allowance to cover for the associated costs. Whilst further amendments and changes in the energy policy landscape are anticipated across the sector, several material uncertainty sources have been identified as particularly likely to impact on our expenditure exposure throughout T2. A reopener is proposed for these uncertainties, which would require a justification for each uncertain cost activity.

Legislative changes following Brexit

The timing and impact of the UK leaving the European Union continues to be unknown. As a result of this process, additional costs may be incurred due to changes in import tariffs or other legislation affecting the costs we incur. Given the lack of clarity relating to when the UK's BREXIT negotiations will conclude and the changes this may lead to, we propose to use this mechanism only in the event that a material change to efficient costs is experienced such as increased import tariffs.

Legislative changes for the 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 as well as an interim objective of 75% reduction by 2030.

These could affect any part of our business operations with various levels of impact. An example of this is the recent[3] experience with the revision of the Regulation (EC) No 850/2004 on persistent organic pollutants which reinforces the urgency of SPT having access to funding to ensure we remain compliant to any upcoming legislative amendments. This change relates to the use of polychlorinated biphenyls (PCBs), which have been linked to reproductive and immunotoxic effects in wildlife and their use has been effectively banned[4] in the recent legislative revision. Due to this change to legislation, our draft plan from October was revised to include this new legislative requirement. This is an example of such as legislative change which can emerge in a short timescale and result in additional, material costs.

Whilst no further immediate legislative changes have been identified, SPT use a range of technical solutions and materials across our networks which may be subject to future legislative restrictions. One example of this is Sulphur Hexafluoride (SF_6) which is a gas used extensively in electricity transmission and distribution as an insulator and arc-quenching medium in high voltage equipment such as circuit breakers, gas insulated switchgear (GIS) and gas insulated busbars (GIB). SF_6 is, however, a fluorinated gas (F-gas) and a potent greenhouse gas with a Global Warming Potential (GWP) 23,900 times that of CO2. Given the newly established net zero target, which also relates to the use of SF_6, the likelihood of legislative amendments aimed at reducing the use of this gas is perceived to be relatively high.

Physical security (PSUP)

Because we operate an essential service, some of our assets can be classified by the UK government as Critical National Infrastructure. The affected sites can change when the responsible government body assesses the current situation. This assessment can lead to additional works being required at any point outside the business planning process and hence represent an area of uncertainty SPT cannot accurately budget for in our baseline costs. The mechanism is necessary to provide funding for licensees to respond to needs for enhanced security identified by BEIS or other relevant government department.

Wayleave review adjustment

[3] Updated legislation came into effect on July 15 2019.
[4] The regulation requires that we "shall identify and remove from use equipment (e.g. transformers, capacitors or other receptacles containing liquid stocks) containing more than 0,005 % PCBs and volumes greater than 0,05 dm3, as soon as possible but no later than 31 December 2025".

We generally pay the landowners and occupiers for wayleave rights for assets on their land with an annual payment, although in some cases we make a one-off payment. These are calculated to match the owner or occupier's loss due to our equipment being on their land. There is an ongoing review across Great Britain which may lead to some significant increases in the wayleave payment rates. TOs (and DNOs) have been engaged over recent years with the National Farmers Union (NFU) supported by an independent professional organisation in a bid to undertake a national review of the current compensation rates. There is also a likelihood of a future review relating to the rent payable for apparatus on farming land. This review may lead to additional costs in relation to wayleave payments. On completion of the review the cost impact should be easily demonstrable by calculating the revised rates by apparatus type and volume.

Planning requirements

Major projects can be subject to unexpected planning requirements to gain consent for the construction works. These are highly uncertain and subject to a judgement made by the relevant planning authority based on policies, which change over time, and local situations. These can range from visual and environmental mitigation measures through to the removal of adjacent assets to minimise the impact of the new infrastructure. An assessment of foreseeable costs associated with this work has been included as part of our baseline projects, detailed in BPDT B4.10 (Planning consent requirements), but further costs may emerge depending on developments to the planning process which cannot be estimated. A reopener under this category would be directly linked to a decision by the relevant planning authority requiring SPT to undertake specific works.

Non-rechargeable Diversions

Non-rechargeable diversions or compensation payments are triggered by land-owners or developers as a result of the ownership of land being transferred or where no current valid land rights exist due to historical land-rights no longer being valid. Whilst in some cases this can be resolved by securing new land rights, the valuation principle for securing those rights is based on the associated loss. This must be balanced against the economic value in retaining the asset and in some cases, the associated loss results in a requirement to re-site the infrastructure. We have experienced an increase in the number of these claims as a result of land ownership being transferred, particularly for new housing developments. The associated loss that can arise can be substantial which may lead to the assets requiring diversion.

The loss of land rights is out of our control as we cannot influence the transaction that landowners make nor the future plans for the use of such land. We proactively pursue the management of our land rights in such situations but not every transaction is visible to us.

An example of this in T1 was on an overhead line over land at in Glasgow. This span formed a critical route of the transmission network which was previously held by wayleave from the previous landowner before the land was sold another party. The land on which the overhead line is located was identified for future development. SPT was served a removal notice in 2014 to remove its line and towers.

In parallel to the ongoing Necessary Wayleave process, SPT engaged in a voluntary negotiation to agree a compensation figure based on the perceived loss of developable land and the impact on house value sales due to the existence of the SPT's OHL. The negotiated compensation figure was analysed by SPT to consider the potential diversion costs of the overhead line and in both cases, diversion was deemed to be significantly higher than the compensation agreed to retain the line and obtain permanent servitude rights.

Examples such as this are becoming more prevalent and it is not reasonable to make an ex-ante forecast of such costs, as this risks exposing consumers to additional costs which may not materialise. The trigger for a reopener would be the third party serving notice for such a diversion.

£10.51m of funding is included in our baseline plan for this activity based on run-rate and known projects (BPDT C4.3b, Injurious infection and N/R Diversion (RIIO-T2). Should less activity than this materialise, we intend to use this as a 'Use it or lose it' funding.

Flood resilience

The effects of climate change are very uncertain and to provide an improving understanding of future changes related to coastal, fluvial and pluvial flooding, the Scottish Environment Protection Agency (SEPA) frequently reviews their flood risk mapping. We expect that Scottish Environment Protection Agency (SEPA) will review and update their flood models to take

cognisance of the updated climate change projections detailed in UKCP18 (published in Dec 2018). SPT expects that as a result of this, revised modelling and mapping new threats from flooding will be identified. A mechanism is required which will accommodate additional costs that are identified as a result of new flood risks being identified using the data provided by SEPA.

£5.5m of baseline funding is included in our business plan to account for known projects, see table C2.24.

Cyber security

The pace of change in the area makes it difficult to predict how our cyber defences will need to evolve. The threats are changing, and the technology available to us is developing rapidly. It is not possible to completely define a baseline level of activity which will be accurate until the end of RIIO-T2. The requirements for the management of cyber security are governed by the Network and Information Systems (NIS) directive and the specifics to maintain compliance can be updated by the Competent Authority.

£12.2m of baseline expenditure is included in our baseline plan for cyber security based on existing requirements, see table D4.8a.

Black start standard

Discussions are ongoing with Government and other relevant organisations regarding the future requirements for transmission owners in the event of a black start event. It is expected that a new standard may emerge, or additional requirement will be placed in TOs to conform to over the course of RIIO-T2. These may be developed by government, other organisations appointed by government or the ESO. Various standards are currently in operation which may be revised including the System Defence and Restoration Plans (https://www.nationalgrideso.com/codes/grid-code/modifications/gc0127-eu-code-emergency-restoration-requirements-resulting-system). The exact requirements for this are unknown however low regret elements that we have identified are included in our baseline plan (see scheme number SPT200128/9 which are captured in BPDT B4.2a and the accompanying EJP). The creation of this standard and code may oblige TOs to undertake further works to comply.

Energy Data Task Force requirements

The publication of the Energy Data Taskforce (EDFT) and Ofgem's requirement for provide a Digitalisation strategy has set an additional requirement of the information which network operators are expected to share and new processes that should be established. The timing of the publication of the EDTF report is relatively late on in this RIIO-2 business plan development process and as such no accurate cost estimates can be included in our baseline calculations to provide an allowance for funding any digitalisation opportunities identified as we update our strategy. It is our view that an uncertainty mechanism is an appropriate solution to allow expenditure adjustments as we iterate this strategy in the future. In particular, any efforts of receiving and acting on feedback on the strategy document from current and future users of Energy System Data will likely incur costs which are currently uncertain and hence excluded from baseline allowances.

In an absence of this uncertainty mechanism, there is a risk that TOs will struggle to identify funding sources and potentially hold back the coordinated industry wide effort to expedite whole system solutions, including the example of modernising energy data.

Environmental Enhancements

The transition to Net Zero will not only require us to facilitate the wider changes to the energy sector, but also ensure that we take appropriate actions to address our own environmental impacts. The operation of the network and construction of new assets all have carbon and other environmental impacts which we are seeking to minimise.

We have included a number of commitments as part of our business plan in the chapter 'An Environmentally Sustainable Network' on pages 35-47) in relation to the steps we will take to reduce the environmental impact of the network. These include:

- We will target zero environmental regulatory interventions and notifiable breaches of legislation.
- We will implement a programme to identify, risk assess and address high risk legacy land contamination.

- We will work collaboratively with our stakeholders, including the other Transmission Operators, throughout RIIO-T2 to develop and pilot a common approach and robust methodologies for delivering Biodiversity Net Gain alongside Natural Capital assessment and enhancement.
- We will pilot these biodiversity and natural capital assessment methodologies and associated tools on selected RIIO-T2 projects.
- We will embed these biodiversity and natural capital assessment methodologies and associated tools in our business decision making processes for projects and the management of existing sites.
- We will identify, and subsequently monitor and annually report, metrics to baseline and track the levels of biodiversity and value of natural capital on our sites and the achievement of our targets.
- We will work with our local communities, landowners and other stakeholders to deliver 'no net loss' in biodiversity and identify options for delivering 'net gain'. (We have proposed a bespoke discretionary financial Operator Defined Incentive that includes a reward for delivery of biodiversity net gain as one of three components. Cost recovery is not part of this ODI.)
- We will work with our local communities, landowners and other stakeholders to deliver a net positive impact in natural capital across our existing sites.

In respect of biodiversity, a means of measuring levels of biodiversity and any improvements is still being developed by the Scottish Government and Scottish Natural Heritage. We expect this will require all construction projects to have no net biodiversity impact as a minimum, moving to a net gain target, potentially during the T2 price control period (as is happening in England). Even once a metric and target are identified, the associated costs of the work required to deliver the targeted improvement will be very site specific. Various environmental upgrades will be required to our network on a site by site basis, relating to ecological impacts, legacy land contamination or other environmental impacts that require resolution or improvement

The full range of activities required to deliver these commitments and reduce our impacts cannot be identified at this time. Therefore, the costs associated with the necessary biodiversity and land improvement works are not included in our baseline costs. This is due to:

- Lack of maturity of consideration and management of the issue (e.g. lack of data, metrics, management processes and/or Government policy)
- Site or project specific nature of the required activities; and
- Potential legacy issues at some sites that are not recorded in current systems.

We do not believe it is in the best interests of the consumer to forecast such costs on an ex-ante basis as the associated targets and means of achieving the targets are not yet defined. Therefore, a mechanism is required to fund these steps efficiently.

We will be establishing a baseline for our existing sites before and into the first year of T2, and thereby identifying a metric against which to measure improvements and target delivery. Each T2 project will also have such a baseline established as part of site survey works. Along with further guidance for Scotland, this will enable us to provide a more accurate and comprehensive cost forecast as part of the reopener.

We estimate the total expenditure on this to be between £13-15m. These solutions are in the interests of wider society as opposed to being related to the operation of the network itself or of benefit to SPT, therefore we consider these to be relevant for funding.

Other legislative, regulatory or standard changes

The exact scope of all legislative, regulatory or standard changes cannot be estimated. A degree of flexibility is required that any other changes made by statutory bodies are included in this mechanism.

8.1 Justification for the mechanism

As outlined above, there is a wide range of potential upcoming changes to the regulatory landscape we operate in, which provides a strong rationale for including an uncertainty mechanism to allow us to remain compliant as these arise during T2. As these amendments are initiated by external stakeholders and governmental bodies, their timing and financial implications on our operations cannot be predicted at this time.

In proposing these as reopeners, we have considered alternative arrangements including:

- Volume driver – these uncertainties do not have standard volumes that costs can be associated with.
- Unit Cost allowance – there are no standard solutions which would address these uncertainties.
- Pass-through – such an approach may be perceived as removing any incentive on TOs to minimise costs or challenge the need for such a change to take place.

8.2 Ownership of associated risks

The failure to comply with any official legislative or regulatory requirements fundamentally puts SPT at risk of breaching our licence conditions. Ultimately, many of these changes are being implemented for the benefit of end consumers and society more generally therefore failure to implement the necessary changes may be to the detriment of stakeholders more broadly.

For several areas outlined above, costs which are of higher certainty have been included in our baseline plan. To minimise potential costs to consumers, only costs with a high confidence are included in the plan. We regard this as an appropriate means of de-risking costs for consumers.

8.3 Type and description of mechanism

SPT require the price control to remain reactive to changes, particularly with regards to regulatory reviews, as the levels of uncertainty as well as potential implications these may have on our ability to ensure compliance with legal and licence requirements.

Two reopener windows are therefore proposed during RIIO-T2. This would allow the impact to be understood, and sufficient time for evidence to be gathered to justify any changes to allowances.

The first reopener would take place in summer 2023 to accompany the regulatory reporting pack which would be submitted to Ofgem at that time. This would allow any costs which have been logged up prior to the reopener application to also be considered. The second reopener would follow at the end of period review, which would allow any other costs which are logged up to be accounted for, and if deemed efficient and well justified, would be accommodated as part of the close out process for RIIO-T2.

In a consistent manner with other reopeners, any application would require to have detailed outputs, a needs case, and a statement of costs to be provided. Confirmation would also be required that there is no other mechanism for the adjustment of allowed expenditure levels to accommodate this uncertainty. Evidence would be provided for each uncertainty in isolation along with the required revenue adjustment.

8.4 Materiality of issue

For reopeners, a materiality threshold has previously been set at 1% of the average annual revenue of the licensee. In RIIO-T1, this was also subject to the Totex Incentive strength rate. For SPT in RIIO-T1, the materiality threshold was 1% of £266m (£2.66m) adjusted for the totex incentive strength of 50% which resulted in the actual expenditure would have to incur on an uncertainty being more than £5.32m before a reopener could be pursued.

We believe this level of materiality is appropriate, however under RIIO-T2, a different mechanism is proposed to set the totex incentive strength which will be a blended sharing factor dependant on the level of certainty of a company's baseline

plans. The full details of this arrangement are still to be confirmed by Ofgem on how this will be determined but a range of between 15-50% sharing factor has been identified by Ofgem in their Sector Specific Decision.

Because of different sharing factors which companies may be subject to, which are informed by the cost certainty of baseline plans, this could consequently expose different companies to different materiality thresholds. For example, if two TOs are exposed to the same level of uncertainty on a particular matter, however one TO has a very high cost certainty baseline whilst another has a low certainty, the expenditure that they need to incur would be substantially different before a reopener could be triggered. This is illustrated below:

	50% sharing factor	15% sharing factor
Allowed Totex for a particular area– Baseline plan	£ 5,000,000	£ 5,000,000
Actual Spend due to uncertainty materialising	£ 15,000,000	£ 15,000,000
Total additional expenditure	£ 10,000,000	£ 10,000,000
TO's additional cost exposure (as a result of sharing factor)	£ 5,000,000	£ 1,500,000
Customer's share of overspend – materiality value for reopener	**£ 5,000,000**	**£ 8,500,000**

For RIIO-T2, we propose that the materiality threshold for a reopener is based on the total additional expenditure that is incurred, opposed to the adjusted expenditure post Totex Incentive Mechanism (TIM). If the TIM is to be taken into account, this risks an inconsistent approach across TOs before a reopener can be triggered. To ensure a broadly comparable threshold in RIIO-T2 with this change, we are proposing that the materiality threshold will be set at 2% of our baseline average annual expenditure excluding the TIM per individual area. Additionally, it is proposed, a secondary threshold of 4% is applied where there are multiple areas which each do not total 2% in isolation but in total exceed the higher threshold.

It is difficult to broadly estimate the materiality of such a wide range of potential changes however an example of a legislative amendment for the environment and climate change outlined below demonstrates the potential impact and immediate material costs, any one of such amendments has the potential to cause.

Case study: Impact of potential SF6 regulatory amendment

As outlined above, a prospective anticipated tightening of regulations is expected with regards to the use of SF6.

Relevant EU & UK regulations addressing F-gases, which place obligations on operators of the equipment including leak checks on equipment; record keeping; recovery of F-gases; and use of appropriately qualified personnel, include:

- Regulation (EU) No 517/2014 of the European Parliament and of the Council of 16 April 2014 on fluorinated greenhouse gases and repealing Regulation (EC) No 842/2006:and
- Fluorinated Greenhouse Gases Regulations 2015 (SI 2015/310)

Article 21 of the 2014 EU Regulations acknowledges that the technical and economic considerations are important in the context of future reviews of the Regulations. Article 21(4) specifically states in relation to secondary switchgear that “[no] later than 1 July 2020, the Commission shall publish a report assessing whether cost-effective, technically feasible, energy-efficient and reliable alternatives exist, which make the replacement of fluorinated greenhouse gases possible in new medium-voltage secondary switchgear and new small single split air-conditioning systems and shall submit, if appropriate, a legislative proposal to the European Parliament and to the Council to amend the list set out in Annex III of the 2014 EU Regulations.

Though limited replacement solutions deployable at transmission voltage levels have been developed to date, the widespread use of SF_6 continues to pose risks to the environment and it is possible new technically feasible solutions may arise during the RIIO-T2 price control period.

In light of these developments, it is anticipated that regulatory amendments could be introduced over the course of RIIO-T2 and are likely to be aimed at increased environmental protection, potentially enforcing more prescriptive and onerous obligations on SPT to reduce the use of these materials.

Whilst any tightening of the existing regulations represents a significant source of uncertainty, to help outline the materiality of the issue, four scenarios have been set out below to illustrate the impact of possible regulatory amendments:

Possible regulatory amendment	Impact on SPT
Scenario 1: New legislation requires all *newly installed assets at rated voltage 132kV and below* to use SF_6- alternatives.	SPT's current plans for RIIO-T2 are already compliant with this requirement as all new circuit-breakers and GIS installations will use alternative insulating gases where there are market-ready solutions. Annex 7: Environmental Action Plan outlines our SF_6 strategy, highlighting that by using alternative insulating gases to SF_6 where technically and economically feasible, SPT have avoided adding an estimated 6575 Kg of SF6 to our inventory, avoiding additional annual emissions of approx. 35Kg.
Scenario 2: New legislation requires all *new assets* at *all voltage levels* to use SF_6 alternatives.	Whilst some components at rated voltages above 132kV have been proven in service, these are relatively immature and as such forecasting the cost implications of replacing *all new equipment* poses significant challenges. This would lead to substantial additional costs which are not accounted for in our business plan.
Scenario 3: New legislation requires the use of SF_6 alternatives on all *newly installed assets* and *phasing out of existing assets* through retrospective replacement of all equipment using SF_6 at a rated *voltage of 132kV and below.*	Although meeting these requirements is technically feasible, the scale of deployment required to retrospectively replace all assets up to 132kV rated voltage makes the task extremely challenging due to the time and cost requirements driven by the large number of existing assets which use SF6 as an insulation and interrupting medium. Again, this would result in significant additional cost.
Scenario 4: New legislation requires the use of SF_6 alternatives on all newly installed assets and phasing out of existing assets through retrospective replacement of all equipment using SF_6	Whilst SPT are committed to seeking SF_6 alternatives for all new assets where technological solutions exist, the impact of replacing existing assets retrospectively is challenging to quantify due to the lack of technical solutions available to replace SF_6 usage in assets at voltage levels above 132kV. For illustrative purposes however, replacing a single 400kV gas insulated substation can incur costs in excess of £50M.

8.5 Frequency and probability of issue over the price control period

As detailed above, it is proposed that a reopener window in 2023 and 2026 would be used, at which time reopeners in relation to any of the above uncertainties may be considered. These would only apply where the gross expenditure is in excess of the materiality threshold of 2% of baseline average annual revenue for RIIO-T2.

The uncertainty mechanism could be triggered by updates as summarised in the table below:

Source of uncertainty	Trigger
Legislative changes following Brexit	Any proposed adjustment would be linked to a change in tariff levels as this would have a material cost impact on SPT.
Legislative changes for environmental and climate change	Legislation amendment restricting the use of existing technical solutions or imposing mandatory use of new solutions resulting in increased costs
Physical security (PSUP)	UK Government classifies a new site as being Critical National Infrastructure
Wayleave review adjustment	NFU review which may increase wayleave payment rates

Planning requirements	Relevant planning authority decision on additional mitigation measures to be undertaken
Non-rechargeable diversions	Notice served by a third party in relation to land access for transmission assets
Flood resilience	SEPA publishes revised flood mapping data. A review of this information will be required to identify any sites at risk of flooding.
Cyber security	Update to requirements by the Competent Authority in relation to the Network and Information Systems directive.
Black start policy and standards	Requirements set out in any new standards relating to system resiliency or black start standard which are beyond business plan including the requirements set out in the Grid Code such as the System Restoration and System Resiliency Plan.
Energy data task force requirements	Costs associated with the implementation of the measures identified by the energy data task force and other groups which are instigated to implement these actions
Environmental enhancements	Measures that are identified by the competent authority which defines future requirements for construction projects in relation to environmental mitigation.

While the exact frequency and probability of issue is challenging to specify at this time, an uncertainty mechanism to address upcoming regulatory changes is vital to ensure SPT is equipped and ready to comply with any legislative changes as they arise. We propose two application windows during which SPT would have the opportunity to review any developments in the various areas where we anticipate possible changes or amendments over the course of RIIO-T2. This mechanism will only be used in the event that a material change to efficient costs is experienced as a result to regulatory amendments.

8.6 Management of Drawbacks

This mechanism creates additional cost exposure for network users, however we are obliged to comply with relevant legislation and regulations which impact our operations. Consideration has been given to other mechanisms to account for this approach but given the nature of the uncertainties and costs which may arise, we view a reopener as being the only means to addressing these issues.

This approach will require greater intervention from Ofgem, however the application of a material threshold ensure that any proposals or of sufficient value to merit a detailed review. This approach also removes potential overlap and reduces the administrative burden of multiple mechanisms for Ofgem.

8.7 Further work

We have sought to provide a clear definition of the triggers that would lead to these reopeners being justified. We have tried to keep this mechanism simple, with clear definition of the triggers and a concise reopener window.

EXTERNAL FINANCIAL UNCERTAINTY

9.0 FINANCIAL UNCERTAINTY MECHANISMS

As a network owner, we are subject to a number of areas of expenditure which are treated differently from expenditure on the network. A variety of uncertainty mechanisms are used to cover the changes related to the funding arrangements for network operators. This includes taxation, funding indexation and other charges such as business rates which are subject to change and adjusted accordingly. These are consistent with previous price reviews and we are not proposing any change to those detailed below compared to RIIO-T1.

Ofgem are also reviewing parties responsible for Transmission Network Use of System Charges (TNUoS) revenue collection. In Ofgem's Decision on the RIIO-2 financial methodology and roles framework for the ESO (25 Oct 2019), Ofgem propose to consult on where the cash flow risk associated with the collection of TNUoS charges is best placed. Ofgem note they will work with the ESO and TOs to consider any implications that could have for the price control determinations (para 2.81 - 2.83). If a decision is made that TOs are responsible for this, then a further uncertainty mechanism may be required as a result. As this policy area is not yet defined, we have not included this below but should be considered as part of the process.

9.1 Issue that the mechanism addresses

Business Rates

Business rates are another example of a cost SPT have little control over as they are mandatory, determined by external independent assessors and their levels are calculated based on regular re-valuations of assets. Considering the timing[1] of the next planned re-evaluations, it is very likely business rates costs will change during the RIIO-T2 period. Whilst SPT will endeavour to take actions to minimise the rating valuations where possible, this area does represent another anticipated source of uncertainty.

Inflation indexation of RAV and allowed return

Inflation indexation of regulatory asset value and allowed returns is also a continuation of an existing uncertainty mechanism, which is an effective way to protect SPT against economy-wide effects of inflation.

Cost of Debt Indexation*

Full indexation for setting the cost of debt allowance is transparent and can be calibrated to provide a good estimate of efficient sector debt costs. In RIIO-1 Ofgem adopted an indexation approach, whereby the allowance was benchmarked annually against a predefined index. The chosen index was a 10-year trailing average of the outturn yields of the iBoxx A and BBB rated sterling non-financial bond indices with a maturity of more than ten years. In Ofgem's Sector Specific Methodology Decision (SSMD) publication, they revise their working assumption for GDNs and TOs, basing on an 11-15-year Trombone of the A/BBB iBoxx index, less the expectation of CPIH inflation. We support the recalibration of the RIIO-1 index.

Tax liability allowance*

A financial model is used to calculate a tax allowance on a notional basis, as a proxy for efficient corporation tax costs, for each of the relevant licensees. A tax trigger mechanism that reflects changes in tax rates, legislation and accounting standards during the price control period mitigates the risk to both consumers and the company.

Pensions - Pension scheme established deficit funding

There is a long-standing commitment to consumer funding of deficits in defined benefit pension schemes, which were generally in existence before the energy network sector was privatised. To reflect this commitment price controls provide a

April 2021
* Please refer to the financial annex for more detail

form of pass-through funding by consumers of 'Pension Scheme Established Deficits' (those attributable to service before certain specified cut-off dates).

Cost of equity indexation*

Ofgem have proposed a method for updating the risk-free rate to reflect changes in UK government bond yields ("equity indexation"). The risk free rate is used in setting price controls for UK utilities, recognising that we are setting future period returns for a long horizon investment The proposal is this will be done by updating the allowed return on equity to reflect changes in the risk-free rate only, referring to data prior to the financial year beginning, and to long-horizon inflation forecasts (t+5 from OBR).

The issues listed above have been pre-determined by Ofgem as anticipated sources of uncertainties along with proposals of how to mitigate risks associated with them. We agree with this assessment and are supportive of the mechanisms proposed to address these sources of uncertainty.

9.2 Justification for the mechanism

There are a number of financial uncertainty mechanisms which Ofgem have identified from RIIO-T1 and will continue to implement in RIIO-T2. The inclusion of these mechanisms in RIIO-T1 proved to be an effective means of tackling various finance related uncertainties and hence their continuation through to the RIIO-T2 price control period seems prudent.

9.3 Ownership of associated risks

As these mechanisms have been tried and tested through the RIIO-T1 period, there are no perceived risks of including them in for the RIIO-T2 price control period.

9.4 Type and description of mechanism

Issue	Proposed mechanism
Business Rates	**Pass through**
Inflation indexation of RAV and allowed return	**Indexation**
Cost of Debt Indexation	**Indexation**
Tax liability allowance	**Reopener**
Pensions *(pension scheme established deficit)*	**Reopener**
Cost of equity indexation	**Indexation**

9.5 Materiality of issue

Due to the practical nature of these mechanisms, being mostly pass-through or indexation, the financial impact of their anticipated use is difficult to quantify at this time.

9.6 Frequency and probability of issue over the price control period

As evidenced by Ofgem's own proposal for these uncertainty mechanisms, their requirement in RIIO-T2 period is undisputable. This is because the issues these mechanisms tackle have nationwide impacts and therefore are unavoidable

and expected to affect all transmission operators. The use of these mechanisms is expected to be in line with their use in RIIO-T1, although exact frequency or magnitude of their use is difficult to forecast given their uncertain nature.

9.7 Management of Drawbacks

There are no perceived drawbacks associated with these uncertainty mechanisms.

CONCLUSION

Most aspects of our plan are relatively predictable however as shown in the mechanisms outlined other areas are less so. Agreeing funding for these would not be efficient if they fail to materialise. Using uncertainty mechanisms gives SPT suitable flexibility through the price control period to adjust for changes and increase or decrease of allowance according to these emerging needs.

We have sought to provide a comprehensive view on the mechanisms which we believe are necessary to manage future uncertainty and justification for them. We recognise that as these are drafted into the licence

We have utilised lessons learned from T1 and identified additional uncertain areas through in-depth analysis and stakeholder engagement. We are currently working with Ofgem and other transmission owners to understand the level of consistency that can be implemented across the industry for uncertainty mechanisms.

APPENDIX A:
SNAPSHOT TABLE OF UNCERTAINTY MECHANISMS

UM name	Is the UM included in May SSMD?	Description	UM type	Reference in Business Plan?	Costs associated with the UM		Associated outputs, UM or CVP proposals in our Business Plan?
					Funding in Business Plan?	Forecast cost / BPDT reference	
Uncertainty Mechanism - Generation Sole Use	N	Utilised to cover generation connections over and above the baseline (900MW) proposed as a PCD - Sole/Shared Use Mechanism required to fund up to approximately £506m of additional costs based on current contracted generation	Volume Driver	Page 140	Baseline costs included	Baseline costs included - £40m (B4.2a Scheme Summary) estimate of uncertainty mechanism provided in business plan pg 140. See also Annex 20	Generation Connections - Sole Use - 900MW
Uncertainty Mechanism - Generation Shared Use	N	Utilised to cover generation infrastructure installed over and above the baseline (2027MVA) proposed as part of the baseline proposed as a PCD - Sole/Shared Use Mechanism required to fund up to approximately £506m of additional costs based on current contracted generation	Volume Driver	Page 140	Baseline costs included	Baseline costs included - £69m (B4.2a Scheme Summary) estimate of uncertainty mechanism provided in business plan pg 140. See also Annex 20	Generation Connections - Shared Use - 2027MVA
Uncertainty Mechanism - Major Boundary Upgrades Strategic Wider Works	N	Utilised to cover additional boundary upgrades currently not forecast through the business plan ex-ante allowance with a value >£100m. Currently proposed to fund only the Eastern Link HVDC but will be utilised to cover schemes that develop through the NOA process undertaken by the ESO - currently forecast to fund additional costs of £1.7Bn - £2.5Bn	Reopener	Page 141	Not Included	Estimate provided in B4.10 and in BP on pg 141	Wider Works
Net zero operability challenges	N	New issues are likely to emerge in RIIO-T2 such as voltage or harmonics which are non-compliant with the relevant standards. A mechanism allows additional allowance to be provided should further work, beyond those proposed in the business plan, be required.	Unit cost allowance	Page 141	Baseline costs included	"Baseline costs included £52.389m (B4.2a Scheme Summary) estimate of uncertainty mechanism provided in business plan pg 141.	No

Net zero transition reopener	N	The transition to Net Zero is likely to result in further changes to the demand and generation make-up across Great Britain. This mechanism is to specifically consider projects of less than £100m that may emerge during the course of the price review and cannot be addressed by the other mechanisms.	Reopener	Page 141	Not included	Use of the mechanism is uncertain	Unknown
Uncertainty Mechanism - Demand Connections	N	Utilised to cover Demand schemes (SP Distribution & Network Rail amongst others) that may arise over the course of the RIIO-T2 period above the agreed baseline schemes - Estimated value if required to be fully utilised is £40m	Volume Driver	Page 142	Baseline costs included	Baseline costs included - £116m (B4.2a Scheme Summary) estimate of uncertainty mechanism provided in business plan pg 142	Demand Connections - SP Distribution & Demand Connections - Network Rail
Whole System Coordinated Adjustment Mechanisms	Y	Re-opener - as per SSMD	Reopener	Pg 142	Not Included	No - costs are unknown at this time	No
Uncertain non-load projects	N	We have a number of non-load projects which have significant uncertainties associated with them, such as land purchases, or are interactive with new generation connections. Ex-ante cost will be agreed with Ofgem as part of the price review but will only be triggered if required.	Unit cost allowance	Pg 142	Not Included	Projects listed in BPDT 5.18. Total value of £147m	One of the main uncertainties for these projects are load projects which may arise at these sites for new generation connections or wider works.
Cyber Resilience	Y	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Baseline costs included	Baseline costs of £12.2m (D4.8a)	No
Physical Security (PSUP)	Y	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Flood Resilience	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Baseline costs included	£5.5m C2.24	No
Climate change and environmental uncertainty	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No

BREXIT	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Wayleave review adjustment	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Non-rechargeable diversions	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Environmental enhancements	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Black start	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Energy data task force	N	Re-opener in 2023 and at end of T2 to adjust revenues to account for this uncertainty.	Reopener	Page 143-144	Not Included	No - costs are unknown at this time	No
Financial Uncertainty mechanism	N	Various index, pass through and reopeners for financial uncertainties including business rates	Varios	Page 144	Not Included	No - cost changes are unknown at this time	No

APPENDIX B

Scheme	Costs £ (2018/19)	Units	Each
Extension			
ASACS 'A'	£370,246	3	£123,415
ASACS 'B'	£330,379	2	£165,189
New Scheme			
Overload protection			
Torness s/s	£280,956	1	£280,956
Eccles s/s	£280,956	1	£280,956
Fallago s/s	£288,386	1	£288,388
Smeaton s/s	£280,956	1	£280,956
Wishaw s/s	£280,956	1	£280,956
Crystal Rig s/s	£310,684	1	£310,684

Extension (link to station) based on mean value above	£144,400.00
New Scheme per site (excluding link to station) based on mean value above	£287,200.00