Annex 7.4
Decarbonisation Uncertainty and Ofgem Uncertainty Mechanisms

Northern Powergrid: our business plan 2023-28

Introduction

As set out in our plan section on uncertainty and risk, as a business we have the ability and experience to manage a wide range of risks on a day-to-day basis, ranging from the immediate issues that could delay restoration of a power cut through to long-term risks to our asset base that could raise our costs if not mitigated.

Part of the rationale of having a regulated, privatised network business is to allocate risks to the regulated company to manage, insulating bill payers and taxpayers from them, and ensuring the business in question has strong incentives to manage the costs of the risk down (so that customers can enjoy lower costs over the long term). In line with best practice regulation, it is therefore right that we continue to bear these risks as the party best placed to manage them. However, there are some risks that it would not be in the interests of our customers for us to accommodate, for example because they are completely beyond our control, or because the potential financial “cost” of insuring a risk away would be prohibitively expensive (and be an additional cost that customers would ultimately have to bear). Therefore, best practice regulation also sees some risks transferred to the customers of a regulated business.

We are proposing no additional regulatory uncertainty mechanisms beyond those our regulator thinks offer good value to customers and should be in place for our whole sector. But as set out in the risk and uncertainty section of our plan:

– the pace and pathway of the net zero transition is the biggest known uncertainty for our business; and
– uncertainty mechanisms will be put in place by our regulator to manage unexpected eventualities.

This annex covers these two points in more detail, in turn. Its main focus is decarbonisation uncertainty, given the prominence of this among the range of uncertainties we face, the significant investment associated with that area, and the importance of the issue to society more generally. In summary:

– our planning scenario sees us building assets that will be used soon under any credible pathway to net zero;
– in this plan we have identified the costs that we think need to be funded through baseline allowances;
– future deliverability, especially of investments in our local high and low voltage networks, is the key reason for supporting this level of investment over 2023-28;
– a set of agile uncertainty mechanisms is needed to provide funding above this baseline level, if the transition towards net zero is faster (for example in line with our planning scenario);
– we think the main uncertainty mechanism should be an additional cost allowance per heat pump (HP) or electric vehicle (EV) coming into use in our region, above the number our base allowances cater to;
– other mechanisms, for example based on the number of customers who need an upgraded service connection to their house, should supplement this; and
– Ofgem must strike a balance in how it manages uncertainty in this area.

Beyond this, this annex gives a summary for stakeholders of the main uncertainty mechanisms that our regulator is proposing to put in place or retain for electricity distribution from 2023-28.

Decarbonisation uncertainty

This section of this annex provides more detail about how uncertainty over the decarbonisation pathway relates to the costs in our plan. It:

- explains the nature of the uncertainty we face and the analysis we have undertaken to determine the proportion of our planning scenario that should be funded through baseline allowances; and

- provides our view on the appropriate agile regulatory mechanism to flex allowances upwards from this baseline level, to our planning scenario or even higher, if necessary.

The level of investment that should be funded through baseline allowances

Baseline allowances should provide funding for investment to ensure that our network can accommodate low carbon technology (LCT) uptake that is consistent with the CCC Headwinds scenario. That would enable us invest £405m in reinforcing our network between 2023-2028 so our network can accommodate approximately 790,000 EVs and 290,000 HPs.[1], excluding any costs directly attributable to connecting new developments.

Our planning scenario accommodates the pace of low carbon transition that we think is supported by the evidence

We have developed our planning scenario based on an extensive analysis of the pathways to net zero that are currently credible. Details of this analysis are set out in our scenarios and investment annex. Many of these credible scenarios are closely aligned to the scenario we have ultimately adopted as our planning scenario, in terms of the costs that they would involve. However, some slower uptake scenarios are still credible, and these would involve lower costs if during this regulatory period we invested only to meet immediate needs.

We recognise that, if the pace of the transition is much slower, it would be appropriate for us to invest at a slower pace to help reduce costs to energy consumers

Although our planning scenario is our best view of requirements over 2023-28, it is of course possible that a slower transition will mean it is not necessary to spend this full amount over that period.

For this reason we have assessed in detail the appropriate balance between regulatory cost allowances being fixed upfront, in the form of baseline allowances that facilitate long-term investment decisions to be made, or on a much more flexible basis, once the need for expenditure has become immediate.

Our assessment has focussed on the long run interests of our customers. We have therefore sought to identify those factors which could reduce the long term cost to meet their requirements, while recognising the inherent risks and uncertainties that are involved. To do so we have taken into account the:

- potential future risks to delivery of our investment programmes if we start slowly and then have to accelerate;

- economic, net present value, cost to consumers of investing earlier than necessary;

- counter-balancing benefits from earlier investment, in the form of lower electrical losses;

- risks of the assets we are making becoming stranded; and

[1] These costs do not include those costs which are directly attributable to new connections, which are covered in the Socialisation of costs - Access SCR and Net Zero Service Upgrades annex

- scope for synergies between asset replacement and load related expenditure to be lost if investment is progressed more slowly.

We set out more detail on each of these points, and the outcome of our analysis, below.

If we invest too little in 2023-28, it could become impossible to catch up with government targets in future

Our planning scenario has been set on the basis of the government achieving the pathway implied by its 10-point plan to net zero.

Of course it is possible that, in reality, society starts out at a slower pace towards decarbonisation than the 10-point plan pathway. In that case, there would be no short-term issues with slowing down and investing less in our network over 2023-28. But if we allow ourselves to fall too far behind the pathway to decarbonisation that the government's 10-point plan implies, then there is a real risk that we would be unable to keep pace with the eventual pathway if society gets back onto that 10-point plan curve or beyond.

We do not think this is a risk that we, or society, should be prepared to take.

Delivering a major investment programme at an efficient cost and with limited delivery risk is always a challenge. It involves taking time to scale up, so that skilled people and supply chain can be identified and mobilised effectively. In effect, an efficient pathway depends on:

- using flexibility to manage constraints and delay investment where possible, and then, when that can no longer cost-effectively manage the constraints, moving on to investment;

- broadening our base of people with the right skills to deliver this investment, many of which require close tuition and 'learning by doing', for example via apprenticeships, which limits the scalability of the training we can offer, and the speed at which these types of training programmes can be grown – particularly when combined with the obvious safety risks if our staff are not trained properly; and

- our suppliers making their own investments in the people, machinery or factories that they need to meet our requirements for services or materials.

If this approach is not taken, and a much quicker scale up is then needed, there are many potential delivery risks:

- making large increases in investments over a short space of time always carries deliverability risks – any unanticipated delays could quickly become critical;

- all companies would be likely to be scaling up significantly at the same time, which could create a supply chain crunch and mean that 'hiring in' the necessary skilled labour would become costly or effectively impossible; and

- upgrades to electricity distribution networks involve many dependencies, such as arranging wayleaves and putting in place permits for street works, each of which could create a bottleneck.

In this scenario, if we were not able to scale up fast enough, our electricity distribution network would become a constraint on the ability of our customers to power the EVs or HPs that government policies were successfully encouraging them to buy.

The potential risks to us being able to catch up with society's aspirations can be seen even at a high-level

The chart below illustrates how this deliverability risk could materialise, by looking at how pathways for energy demand could potentially evolve over the next 15 years.

The solid red line in the chart underpins our asset investment plan and is consistent with the government's 10-point plan. The grey area shows the range of plausible scenarios, based on:

- the lowest of last year's DFES scenarios (DFES 2020 system transformation), prepared before the 10-point plan; and
- the Climate Change Committee's (CCC) widespread engagement scenario at the top.

The dotted red line shows a scenario where:

- society continues to make gradual progress towards decarbonisation over the next seven years; and
- this trajectory steepens from 2028 onwards, for example because of technological breakthroughs (which might make new things possible, or reduce costs significantly), major government policy initiatives, or a significant change in consumer behaviour for any other reason.

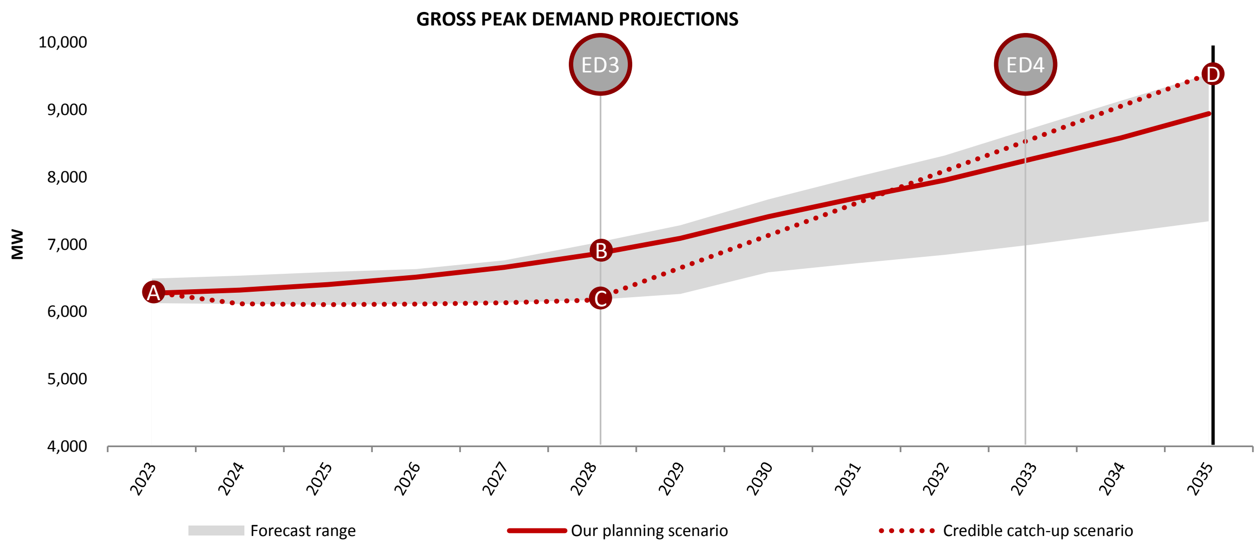

Figure 1: Gross Peak Demand Projections

Each of the points marked on the chart involves a different level of uptake of EVs and HPs; and therefore the slope on the graph represents the rate of new uptake as we move between those points. The table below sets out exactly what this means in practice:

Point on chart	No of EVs	No of HPs	Total
A – 2023	125,000[2]	59,000[2]	184,000[2]
C – 2028 (low)	419,000	172,000	592,000
B – 2028 (planning scenario)	941,000	309,000	1,250,000
D – 2035 (high)	3,222,000	1,585,000	4,807,000

Table 1: The number of EVs and HPs

[2] Different credible scenarios involve slightly different levels of uptake by 2023 – for illustrative purposes we have used an average of these levels

As can be seen by the chart and the associated table, our planning scenario involves a gradual curve starting from 2023, with the pace of uptake growing as time goes by. Between 2023 and 2028 the number of EVs or HPs we were accommodating would increase by 1.3m, from about 0.3m to 1.6m. This is equivalent to making capacity available for about 260,000 per annum. Under this scenario, even after the benefits of price driven peak load shifting and additional flexibility solutions we deploy, we forecast we would need to increase our investment in general reinforcement from about £20m per annum at present to around £109m per annum[3,4]. Delivering this would involve a significant but steady increase in delivery capacity (in the form of people and supply chain). This scale of increase is not inconsistent with the cycles of investment we have already managed since 2010.

If instead we were to follow a curve where society moves from point A to point C during 2023-28, gross peak energy demand would fall behind our current planning scenario, while the number of EVs or HPs in use in our regions would rise from about 0.3m to only 0.6m, an increase of around 80,000 per annum. In that short-term period, fewer investments would be needed, with reinforcement of about £45m per annum (a reduction of about £64m per annum compared to our planning scenario). We could therefore save money, at least for a while.

However, if society then corrects course in 2028, moving from point C to point D, demand would outstrip our current planning scenario around 2031. Between 2028 and 2035, the number of EVs and HPs in use in the regions we serve would increase from 0.6m to 4.8m – at a rate of nearly 850,000 per annum. Rather than taking ten years to build the necessary skills and supply chain and to make all the associated investments our planning scenario envisages by 2031, starting today, we would have only three years – between 2028 and 2031. And we would need to increase our reinforcement investment programme from about £45m per annum in 2028 to £230m per annum.[5] The potential risks to deliverability would be significant.

Stepping up progressively from about £20m per annum to about £109m (A to B) and then to £160m per annum (B to D), based on our current indicative estimates, is still challenging but is much more achievable; and wouldn't store up all of the delivery risk.

Underinvestment in our local high and low voltage networks represents the biggest risk

As well as looking at overall expenditure to identify the potential for deliverability risks at a high level, we have looked at our investment programme for each of the major voltage categories, since the work needed to deliver investment in each category can be very different.

The analysis quickly demonstrates that investment on the local networks, operated at high and low voltage, is where there is the most scope for future deliverability challenges. This type of investment is labour intensive and requires highly skilled labour with specialist knowledge and equipment to deliver it.

The chart below shows our total investment in our high and low voltage network under a range of scenarios, including investment in our main network as well as investment to unloop service cables; see our scenarios and investment annex. We have included replacement of old assets as well as investment to add capacity because the activity is undertaken by identical people using the same tools, installing similar or even the same assets.

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[3] In order to show how we have determined our December 2021 request for ex ante allowances we have presented the figures in this annex using our July 2021 planning scenario. As an outcome from this analysis, our December 2021 planning scenario has taken a different approach to how some synergies between asset replacement and reinforcement are presented and some of the figures in this annex cannot be compared directly to other parts of our December 2021 plan.

[4] This and all subsequent figures quoted in this annex are without any input price increases over time, so they directly illustrate the increase in volume of activity.

[5] These figures assume an overnight increase in expenditure starting in 2028. Any glidepath to reach this higher annual expenditure would increase the necessary rise in annual expenditure.

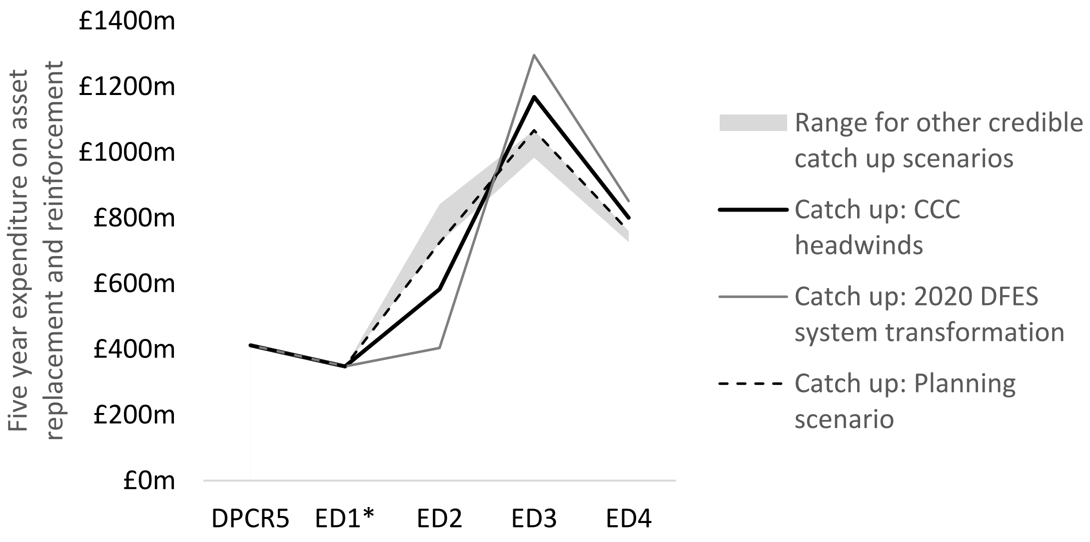

Figure 2: High and low voltage investment under catch up scenarios[6]

The approach to developing the scenarios is identical to the approach presented in the previous sub-section. The catch-up scenarios for 2028 to 2033 (and beyond) involve following a scenario where decarbonisation proceeds slowly at first over 2023 to 2028 but then catching up by 2035 to a scenario which is consistent with the Government's 10 point plan and sees society moving at pace in this direction (the widespread engagement scenario).

The chart shows that, if we invest in line with the DFES 2020 system transformation scenario over 2023-28, we would:

- barely increase our 2023 to 2028 delivery of investment on these parts of the network above current levels; and
- face a potential requirement to increase by £892m, over the course of the five years from 2028 to 2033, relative to levels over 2023 to 2028.

More than tripling our delivery capacity for this type of activity, which involves significant skilled labour input, is unlikely to be possible over a short period. Our ability to scale up in this scenario would be further limited because all electricity distributors would need to scale up at the same time, limiting our options to draw in delivery capacity from elsewhere.

In contrast, if we follow the CCC headwinds scenario as a minimum baseline over 2023-28, we would:

- increase our investment on these parts of the network by £235m above current levels; and
- moderate the potential step up between the five years 2023-28 and 2028-33 to £585m.

Doubling delivery capacity of this type of work over 2028-33, compared to 2023-28, in a catch-up scenario would be challenging, but it would be more manageable if we were further increasing the capacity of a business that was already scaling up. So overall it would be much less challenging than tripling from a base that we (and the sector) hasn't scaled up for well over a decade.[7]

[6] (*) ED1 total is quoted as a 5-year equivalent for comparability.

[7] We also considered other voltages in our analysis. But these are not as relevant to the issue of potential catch up risk. For the highest voltages on our network, where the equipment is at its largest, our investment programme does not vary a great deal between the credible scenarios. We also need to undertake a significant amount of investment to renew ageing assets in any case. So even though we will also need to add some extra capacity under all the credible scenarios, the incremental investment (as a proportion of the programmes we need to undertake anyway) is not as large.

The risk of stranded assets under our planning scenario is low; these risks are even lower under our proposed baseline allowances

When building long-lasting assets, there is always a risk that things might be built that:

- are not used as quickly as expected when they were built;
- are simply never used; or
- that prove to be bigger (and therefore more costly) than was actually necessary.

In network regulation, this is called 'asset stranding' risk, and it can lead to consumers paying more than they should ideally have had to. At a time of significant growth in investment, it becomes particularly important to be aware of this risk and make sure that the approach being taken deals with it.

We have done a lot of detailed work to put together a plan that does not involve a risk of material asset stranding under any realistic scenario.

This is primarily because the drivers of the decarbonisation road map in the 2020s are such that they demand solutions that are common to all of the pathways that could potentially be credible. This high continuity of network solutions translates to a high degree of confidence that the investments we will deliver in our next regulatory period will soon be used and useful on the journey to net zero by 2050, despite the uncertainties around the speed and precise nature of the decarbonisation transition that actually unfolds.

Put another way, it is already possible to identify those areas of our network where EV and HP uptake will most readily push demand to a point where some intervention, either additional flexibility or reinforcement, is required in the early years. If uptake is slower than our planning scenario, it will still be these same areas that require the fewest EVs and HPs to push them to the point intervention is needed, and therefore where investment is likely to be needed soonest. And as we increase our ability to monitor and analyse what is happening on the low voltage (LV) networks, we will be able to effectively target our investment.

We have translated these forecasts for uptake into forecasts for the number on interventions we would need to make. And our current forecasts indicate that even under the slowest pathway we have considered (the distribution future energy scenario (DFES) 2020 system transformation), we would need to undertake:

- as many interventions on our high and low voltage network by the end of the 2028-33 period as our plan involves for 2023-28 (based on our planning scenario); and
- the same set of investments on our extra high-voltage network within the 2023-28 period (i.e. these investments are necessary in this time-frame under any scenario).

So it is highly likely that the investments we have proposed under our planning scenario will still be required within five years even under the slowest low carbon technology uptake scenario. And if we invest in line with our baseline allowances proposal, it is likely that the assets will be required even sooner. This significantly limits the risk of stranded assets.

The net cost of staying ahead of uptake in slow-start scenarios, and keeping options open, is much lower than the cost of the investment itself…

Under all of the credible scenarios for a transition to net zero, our modelling indicates that we will need to undertake significant amounts of investment in the networks that come closest to the communities we serve, at high and low voltages, to facilitate the use of HPs and home charging of EVs.

Our plan involves us targeting those parts of our local network which need more capacity soonest. And even if uptake of EVs and HPs is slower than our planning scenario assumes, these parts of our network will still need to be upgraded relatively soon under all of the credible scenarios. Therefore the cost of faster investment in these parts of the network, compared to a slow uptake scenario, is not the total cost of the extra investment – it is only the cost of having invested earlier than could have been the case, had those investments been left to the point in time when they become necessary.

To place a value on this, we have calculated the net present value (NPV) of investing during the ED2 period, compared to investing along the lowest credible scenario (DFES 2020 system transformation).[8]

…partly because there would be offsetting benefits from lower electrical losses on our network

There are also direct ancillary benefits to the energy system (and energy consumers) from investing in more capacity in areas where our assets are currently relatively fully loaded – because this reduces the amount of electricity that is lost during distribution. Electrical losses (referred to throughout simply as 'losses') are an unavoidable consequence of running an electricity network.[9] And as electricity has become more expensive over time, the cost of losses has risen, and this is a cost that energy consumers ultimately have to pay as part of their bills. So if losses are lower, there will be associated financial savings for energy consumers.[10]

In order to calculate a net cost of investing ahead of the lowest credible scenario, we have therefore also valued the losses benefits. The table below shows our findings.

Scenario	NPV cost of early investment	NPV of losses benefits	Net cost
CCC widespread engagement	£49m	£15m	£34m
CCC Balanced Net Zero	£42m	£13m	£29m
DFES 2020 consumer transformation	£35m	£12m	£23m
DFES 2020 leading the way	£38m	£14m	£24m
NPg planning scenario	£35m	£11m	£24m
CCC headwinds	£21m	£6m	£15m
DFES 2020 system transformation	£0m	N/A	£0m

Table 2: The net cost of early investment if demand progresses according to the DFES 2020 system transformation scenario

The table shows that the net cost of investing according to our planning scenario in the ED2 period would be as low as £24m, even if demand progressed according to the DFES 2020 system transformation.

Under any scenario, we need to exploit synergies between asset replacement and reinforcement to minimise costs of the low carbon transition for energy consumers

If we undertake less reinforcement investment in the 2023-28 period than our planning scenario would involve, there would be fewer synergistic benefits of our reinforcement programme for our asset replacement programme. [11] This is because a smaller reinforcement programme targeted on the areas of highest network loading will involve replacing fewer of our oldest assets for load related reasons.

[8] The NPV cost we have calculated is the lifetime NPV of having made investments early during the ED2 period investments; therefore it includes the continuing cost of these investments beyond the ED2 period but does not include the cost of any further investments from the ED3 period onwards, which would be subject to a separate price control review.

[9.] One reason for losses is that 'larger' assets offer less electrical resistance, and when electricity flows through them less energy will be dissipated in overcoming this resistance. For example, a small cable will warm up more than a large cable for the same amount of electricity passing through it. This conversion of electricity to heat represents a loss to the electricity system and society.

[10.] Further information on these benefits can be found in Imperial College London and Sohn Associates. *Management of electricity distribution network losses.* February 2014. https://www.westernpower.co.uk/smarter-networks/losses/losses-management

[11] This statement applies under our July 2021 approach to splitting the full investment needed in our planning scenario between asset replacement and reinforcement, which accounted for all synergies by reducing asset replacement costs. Our December 2021 plan costs recognise the synergies experienced under our baseline allowance proposal in the same way. Synergies at higher levels of uptake are instead accounted for in the opposite direction – but although the costs have been classified in this way the underlying principles relating to the synergies are all the same.

But old assets that are not upgraded for load related reasons will, however, still need to be replaced, because they are ageing, their performance is worsening, and the risks involved in keeping them on our network are rising.

Less reinforcement therefore necessarily means more asset replacement. But we can still exploit a synergy for our customers– as long as we are funded adequately, we can upsize the assets that we come to replace where we can identify they would need reinforcement in the near future; or where the benefit from reductions in electrical losses would outweigh the incremental costs of the larger installed assets. And the low incremental cost of installing a bigger asset when we have to replace the asset anyway means that it will be relatively common to find cases where the net present value of the benefits from upsizing out-weight the extra costs.

We have taken this into account in our business plan when we have subdivided the costs of our planning scenario between those costs we think should be funded through base allowances and those we think could be funded through an agile uncertainty mechanism. Under base allowances, although reinforcement would be lower than under our planning scenario, asset replacement would need to be higher.

Allowances will need to be adjusted for the decarbonisation risks that we cannot control

As set out above, our proposal for baseline allowances is calibrated to ensure that options for the pathway to net zero are not closed off by storing up too much investment beyond 2028.

This means that allowances will need to increase above those baseline allowances if uptake of EVs and HPs is faster than our baseline allowance scenario assumes, or if other risks materialise (such as less price driven flexibility than our plan assumes, or more frequent requirements to replace shared service cables to facilitate use of a HP or charging of an EV).

In light of the uncertainty, our regulator has already decided that it will put in place a set of agile uncertainty mechanisms for decarbonisation purposes, but it is still deciding how to specify some of the precise mechanism(s).

In short, our views on how these should be specified are that:

- A principled approach must be taken to identifying the customer interest in designing these mechanisms;
- Incentives for efficient delivery of the transition are at the heart of the RIIO framework, and securing value for customers – so this needs to be reflected in uncertainty mechanism design;
- A volume driver based on actual uptake of EVs and HPs is the strongest candidate precisely because it maintains strong incentives;
- A backstop reopener can then cover unanticipated circumstances, allowing the price control to be swiftly reset and then continue with incentives maintained; and
- Service upgrades should be funded through their own volume driver.

We set out more on each of these points below.

A principled approach should be taken in designing these mechanisms

Having identified that an uncertainty mechanism is needed, it is relatively easy to create a design that would protect DNOs from the risks that they face.

But our regulator has a duty to take into account the long-term interests of energy consumers. Of course, it is in consumers interests that companies invest. But from a consumer viewpoint this also needs to be balanced against the risk that a mechanism could fund inefficient volumes or costs of investment.

To strike this balance, there are a number of important properties that any uncertainty mechanism should meet where possible, if they are to not only provide the required flexibility but also complement and support the wider regulatory framework.

- **Releases funding when needed.** The uncertainty mechanism must release additional funding when it is needed. The extent to which the mechanism triggers additional funding should therefore be linked to a reliable term indicator of investment need.
- **Strong efficiency incentives.** Any uncertainty mechanism creates incentives, and good design can ensure that these incentives benefit consumers by encouraging DNOs to reduce the costs of enabling EV and HP uptake where they can. This is even more important when investment in the network will increase significantly.
- **Clear and transparent.** The mechanism should be easy for DNOs and stakeholders to understand. This ensures that DNOs can understand and respond to the incentives created by the mechanism, and also ensures that stakeholders can monitor the operation of the mechanism and hold DNOs and Ofgem to account.
- **Measurable**. In practical terms, it is important that the uncertainty mechanism releases funding based on some factor(s) that can be reliably measured.
- **Limited regulatory burden.** The measuring, monitoring and implementation of the mechanism should not create an excessive regulatory burden.

These features have informed the thinking that has led to the full set of uncertainty mechanisms we have proposed in our plan.

Our favoured uncertainty mechanism design manages risks, has strong incentive properties, and is practical to implement

We strongly favour a volume driver approach that would provide additional funding for each additional EV or HP in use in the regions our network serves, above a pre-specified level covered by baseline allowances.[12] This is because domestic uptake of these new technologies is the big driver of uncertainty over reinforcement.[13]

We believe this is definitely workable for upgrades to the high and low voltage network where costs are most likely to average out. We also think that Ofgem should aim to fund upgrades to our highest voltages through the same mechanism, if possible, by setting a unit cost per EV or HP that is high enough to accommodate this extra investment, since this would maintain the strongest possible incentives across every aspect of our investment programme. But if it is not possible for technical reasons then a more administrative set of funding arrangements for higher voltage investments, based on engineering assessments, could be considered.

This type of mechanism would provide additional funding only if there was a clear and verifiable need, triggered by the pace of decarbonisation.

- The level of uptake of EVs and HPs is a timely and highly relevant indicator of the amount of decarbonisation-driven demand growth on the network. It is therefore a reliable and objective measure of the amount of additional investment needed.

[12] [647,347] EVs and [239,704] HPs, under the assumptions underpinning our plan for how they are typically used.

[13] The costs of reinforcing the network to accommodate larger installations like new solar or wind farms fall on the connecting party under current charging rules, which ensures they take cost-reflective decisions on whether and where to invest. Ofgem is considering changes to these rules and these could warrant an additional uncertainty mechanism. We oppose these changes and our views on them (and how to design a potential uncertainty mechanism if they are taken ahead) are detailed in full in our Socialisation of costs - Access SCR and Net Zero Service Upgrades annex.

- Although individual EVs and HPs may or may not trigger substantial requirements for expenditure, across the large areas our distribution network serve our modelling shows that this should average out – so that a fixed £ per extra EVs or HPs could be used across large ranges of uptake.

- We have been explicit in this plan regarding the volume of EV and HP uptake that is supported by the investment plans funded by our baseline allowances. By linking the release of incremental funding to LCT uptake we can provide comfort to customers that additional funding will only flow if there is a clear and verifiable need (i.e. no additional funding unless uptake exceeds plan assumptions).

Data on LCT uptake could be readily collected regionally, where it is not routinely collected already, without significant cost, making this design implementable without significant regulatory burden. Data could be collected and used in a timely manner to enable funding to be released rapidly, but only when necessary.[14]

- EV uptake is published by the DVLA at a postcode level – and if the relevant forms do not currently capture all of the information needed, they could be revised.

- HP numbers can be collated through DNO connection applications data (for new build HP installations) or from government incentive schemes for retrofit.

- DNOs and Ofgem can also work with government if needed, to ensure that the data remains fit for purpose – for example if HP incentives are withdrawn in future.

Importantly, a mechanism based on EV and HP uptake, not on the volume of work networks choose to do, would create clear and strong incentives for networks to reduce the additional costs of facilitating this uptake wherever they can.

- By releasing funding based on an external measure outside DNO control, DNOs are incentivised to deliver the necessary investment as efficiently as possible, finding innovative ways to limit the volume of work needed and the unit costs of that work, and preserving the incentive for DNOs to find smarter, more flexible non-network solutions

- This will stimulate cost savings that benefit customers over 2023-28 (through the totex sharing mechanism, that returns a proportion of any savings made by DNOs to customers) by delivering the necessary investment to enable the net zero transition as efficiently as possible.

- As these incentives drive companies to find cheaper ways to manage this transition, these cost savings can be factored into future price control arrangements, delivering even more benefits to energy customers.

Such a mechanism would provide comfort to consumers that, if they are asked to fund additional costs, these costs will be both needed and efficient. It should also deliver learnings and innovation during the course of the next five years, that will benefit consumers over the course of the whole net zero transition.

Such a mechanism would also be aligned to the principles underpinning best practice regulation, and Ofgem's totex incentive, that regulatory arrangements should avoid distortions in the treatment of different types of cost. If an exogenous cost driver based on EV and HP uptake is used to adjust totex allowances during the price control period, then the totex incentive would be preserved with no distortions at all.

[14] Timely access to this data for Ofgem and DNOs is also appropriate regardless of the mechanism used – since it will provide much better visibility of the regional pace of the transition, and (if granular enough) could also help electricity distributors better target their reinforcement investment programme.

Backstop reopeners can also be used to reset arrangements if they would give rise to unjustifiable gains or losses

We also recognise that forecasts can prove to be wrong, and there comes a point where a regulator may need to protect energy consumers and investors from unjustifiable gains or losses. Even a very well-designed mechanism could be subject to mis-calibration, potentially leading to electricity distributors being over- or under-remunerated for the investments they need to make. The mechanism would ideally have a protective measure to allow it to be re-calibrated during the period in case this happens.

We would therefore also propose that this uncertainty mechanism should be supported by a fail-safe reopener based on comparing expenditure to allowances. If it becomes clear during 2023-2028 that the uncertainty mechanism was not working as intended, then the reopener should kick in to reset the mechanism, to provide an additional layer of protection to customers (and companies). Once reset, the strong incentives inherent in our proposal could continue to operate.

This is not new. In the current arrangements, our regulator already has in place a back-stop reopener uncertainty mechanism for load related expenditure. If the calibration of our current reopener was maintained, while moving to shorter price control period where customers will receive a bigger share of any cost changes, the potential windfall in either direction could be as low as £15m. This band would not need to change in size as investment rose, but it would, of course, float upwards as the level of allowances was revised by the volume driver mechanism; reducing the likelihood that it would be triggered.

In the 2023-28 period, Ofgem has also decided to put in place a net zero reopener. This could be triggered for other reasons, other than expenditure levels, for example if changes in government policy make clear that baseline allowances need to be revisited. This would for example enable baseline allowances to be increased if the uptake of EVs and HPs was low during the period, but changes in government policy meant that the future deliverability risk was greater than originally thought, and therefore more strategic investment was necessary.

A mix of baseline allowances and volume drivers should also be used to fund upgrades to the service cables for properties already connected to the network

Some of our customers are currently served by a service cable – the final few yards of our network to their property – which is not large enough to handle the future demands that may be placed on them.

- In some cases, the cable might be shared between several properties (called a looped service cable);
- Most customers will have their own service cable but this may be smaller than we would install today.

With many different standards having been used over the years, and with many older houses having been connected much earlier in the 20th century, the supply cable arrangements may be inadequate for meeting the demands HP usage or EV charging would place on them.

Other aspects of the connection arrangement may also need to be upgraded to cater to EVs or HPs, like fuses that are too small.

As set out in our plan, the uncertainty around the speed of uptake of EVs and HPs, and how this will relate to premises that currently have smaller service arrangements, means that it is impossible to accurately predict how many service upgrades we will need to perform over 2023-28, and the resulting level of costs.

For looped services, we think that the volumes will be high enough to warrant part of the programme being funded through baseline allowances; see our costs in detail annex. We have included expenditure on looped services (and potential catch up risk) as part of our analysis above of the appropriate scenario to adopt for baseline allowances.

But in higher scenarios more upgrades to looped services, and funding, would be needed. We therefore think there should be a volume driver for incremental customer driven service upgrade requests, beyond the level catered to in baseline allowances.

We also think that there should be funded a separate volume driver for upgrading service cables (and associated equipment at the end of those cables, called “cut outs”) in response to customer requests.

This volume drivers should count the customer outcomes, not just DNO activity

Setting a volume driver based on customer outcomes helps to ensure DNOs are incentivised to find the cheapest way of meeting these requirements.

In this case the customer outcome is an upgrade in the capability of their service arrangements to allow a 100 amp connection. Counting this outcome will ensure that DNOs have strong incentives to meet this requirement at the lowest possible cost.

Beyond any baseline allowances to fund investment that is necessary to avoid catch up risk, we think there should be a customer trigger for funding, such as a request to install a EV or HP which will cause problems for the existing arrangements. Otherwise if electricity distributors can gain allowances for simply undertaking activity, there will be a strong incentive to accelerate low cost upgrades (potentially leaving more expensive upgrades to later). Many of these upgraded connections would also not be necessary for some time, creating an additional cost to energy consumers (equal to the net present cost of investing early).[15]

Ofgem must strike a balance in how it manages uncertainty in this area

Ofgem must strike the right balance in how it uses uncertainty mechanisms in this area and the extent to which it funds investment now (rather than deferring decisions to later). The balance is between:

- On the one hand:
  - the future deliverability risk that can be mitigated, if we have certainty over our investments; and
  - mitigation of the risk that underfunding (or delays to funding) could result in electricity distribution networks slowing down society’s decarbonisation.
- On the other hand:
  - the affordability of investments;
  - the need to maintain strong incentives on electricity distributors; and
  - any risk of stranded assets.

We will work with Ofgem to optimise the design of these mechanisms ahead of Ofgem’s draft determinations.

[15] Ofgem will also need to take care in the detailed design not to introduce incentive distortions through the volume drivers. For instance, there should be a strong incentive for DNOs to undertake simple fuse replacements (to 100amp) as and when they are visiting premises already and this should be funded through baseline allowances as it is relatively low cost and routine – but providing funding via a volume driver for fuse replacements after a customer call out could distort incentives.

Ofgem's uncertainty mechanisms

Our regulator puts in place a range of uncertainty mechanisms as part of its regulatory framework, which it judges offers a good balance of risk protection versus cost exposure to customers. Some of these are likely to be common across all network sectors, including transmission and gas distribution; others are likely to be specific to our sector, electricity distribution.

We are not proposing any bespoke mechanisms in this plan. Therefore we would only be subject to the mechanisms that Ofgem puts in place for electricity distributors generally. In some cases this may mean that we ultimately receive uncertainty mechanisms proposed by other companies, if they relate to general issues affecting the sector rather than being company specific.

The table below sets out the main mechanisms that our regulator currently proposes will apply to our sector over 2023-28, so that stakeholders who may have an interest in them (such as credit rating agencies or financial analysts) can understand our plan in their context. We have not included those mechanisms Ofgem proposes to remove, which are set out in Ofgem's methodology decision.[16]

Some of these mechanisms are still under development; it is also possible that Ofgem may scrap some mechanisms, or adopt additional mechanisms, after business plan submission, if it identifies that this would be appropriate.

Mechanism	Overview
Strategic investment/load-related expenditure	As set out in our plan and in the first part of this annex, the biggest known uncertainty that our sector currently faces is the level of decarbonisation expenditure. Our regulator has decided there will be a mechanism, or several mechanisms, in this area. It has highlighted that it could include the existing load-related reopener mechanism, high-value projects mechanism, or new mechanisms to adjust allowances based on volumes. The design of the mechanism(s) is still under development. We set out in the section above the risks that we are exposed to but cannot control, and also where we think there is relatively more certainty over the appropriate level of investment.
Net zero reopener	A new reopener that would allow our regulator to reset the price control in line with net zero targets, should these change. This is proposed in addition to the other mechanisms relating to net zero and environmental legislation.
Environmental legislation	A new reopener that would allow adjustments to allowances if a change in legislation would have a material impact on a company's Environmental Action Plan.
Electricity system restoration (Black Start)	A new reopener for costs associated with any changes in requirements relating to system restart after a complete blackout. Changes to requirements are anticipated and this might mean additional costs.
Access SCR mechanism	This is a new mechanism that Ofgem's minded to decision on the Access SCR has made apparent is likely to be implemented. Proposed changes that will make connections cheaper for the connecting customer and less cost-reflective will lead to uncertain impacts on the volume (and average cost of) making new connections, depending on how developers react. We oppose these changes as they will result in connections and network investment that is not cost-benefit justified going ahead. Our views on how the mechanism should be designed are set out in the **Socialisation of costs - Access SCR and Net Zero Service Upgrades annex**.
Coordinated adjustment mechanism	A reopener that was recently introduced that can facilitated transfer of allowances between different RIIO sectors. There are already commercial and licence mechanisms that allow contracting between companies so this mechanism would probably only be triggered in fairly unusual circumstances.

16. Ofgem. *RIIO-ED2 Sector Methodology Decision: Annex 2 – Keeping bills low for consumers*. December 2020. Page 70, table 8.

Mechanism	Overview
Cyber resilience	A new reopener to cover 'new cyber resilience activities, new risks or threats, as well as new statutory or regulatory requirements'. Cyber resilience costs related to operational technology would also be allowed for on a 'use it or lose it' basis.
Rail diversion costs	Where our assets run across railway lines, it is sometimes necessary to divert them (for example when existing lines are being electrified). An existing reopener to cover electrification of existing railways is being expanded to cover diversion costs associated with all rail projects, for example including new railway build, where these costs cannot be recovered from the party in question.
Smart-meter volume driver	An existing volume driver mechanism that allows for the costs of remediating issues with meter points that are necessary so that smart meters can be installed, where we can demonstrate that there is a link between the work and smart meter installation.
Street works reopener	An existing reopener to cover additional costs associated with how street works are managed by local authorities (who have responsibility for this). The most material uncertainty for us relates to potential implementation of charges for renting lanes in roads when they need to be opened (rather than paying a smaller permit fee). Other uncertainties include local authorities amending, expanding, or changing how they operate existing permit schemes (for example because the guidance on how to run schemes is updated).
Enhanced physical site security reopener	An existing reopener is being maintained, to cover any costs incurred in complying with any special obligations we have about the security of specified sites, for sites that have not been catered to in our base allowances (if any).
Improved visual amenity	There is an existing mechanism to provide 'use it or lose it' allowances for improving visual amenity of the network. Ofgem has not signalled that this is likely to be removed.
Established pensions deficit repair mechanism	The existing mechanism to allow for the cost of our pre-existing defined benefit pension deficit obligations is being maintained, and runs every three years outside of the main price control. These costs are beyond our control because we closed our schemes to new entrants over two decades ago, well before most of the other groups currently operating in our sector, and because the pension benefits of existing scheme members are protected by legislation that was put in place at privatisation.
Inflation indexation of allowed revenues	It is necessary to cover inflation in the setting of any price control. Updating the price control formula with inflation is a well-established regulatory mechanism that links the prices that we can charge to movements in general prices. Ofgem has decided to move from the existing Retail Price Index (RPI) to the Consumer Prices Index including owner occupiers' housing costs (CPIH) and has committed to making this a value-neutral change.
Real price effects indexation	A new mechanism to update specific elements of our cost allowances, based on the evolution of a price index other than CPIH. These costs have previously been allowed for through base allowances. Ofgem is changing how it makes this allowance to an indexation mechanism.
Cost of equity indexation	A new mechanism to update the allowed cost of equity for changes in the risk free rate using a specific formula.
Cost of debt indexation	An existing approach to updating the allowed cost of debt is being maintained. The adjustment is made based on the evolution of a trailing average. Ofgem is updating the mechanism and making some adjustments but the general approach is unchanged.
Pass-through of various costs	Existing mechanisms to pass through specific costs are being maintained, for costs that are generally accepted to be beyond our control. These include Ofgem licence fees, business rate costs (subject to an established efficiency check process), the cost of existing transmission connection points, the fixed costs we are charged by the data communication company for the smart meter data system and potentially miscellaneous costs that Ofgem deems meet its requirements.
Tax trigger	The existing arrangements for dealing with changes in corporation tax will be retained, with some adjustments to how it operates, for example to ensure changes to corporation tax rates are always fully reflected.
Tax review	A new mechanism is being introduction to potentially review corporation tax allowances, if a company cannot reconcile its actual corporation tax payments to its corporation tax allowances.
Price control disapplication	There is a longstanding mechanism that allows energy networks to bring about a reference of their price control to the Competition and Markets Authority, which could for example be used if

Mechanism	Overview
mechanism	Ofgem fails to accommodate major costs that companies are required to incur due to new government legislation. The design of this mechanism has been updated for transmission and gas distribution to reduce the waiting period and allow for faster action if the mechanism is ever needed.
Return adjustment mechanism	A new mechanism is being introduced to adjust allowed revenue (and earned regulatory returns) if returns stray outside of pre-set thresholds around the allowed return on equity.

Table 3: The main uncertainty mechanisms our regulator currently proposes

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