# RIIO-2 CHALLENGE GROUP INDEPENDENT REPORT FOR OFGEM ON RIIO-ED2 BUSINESS PLANS

8 February 2022

**Electricity Distribution sector**

# Contents

# 1. Objective, context and overview of this report

The RIIO-ED2 Challenge Group (hereafter, 'the Group', 'we' or 'us') was established by Ofgem in September 2020 with the objective of providing effective challenge to the Business Plans (BPs) of the electricity distribution network companies and to Ofgem, on behalf of existing and future consumers. Our challenge process has run in parallel with the work of the company-specific Customer Engagement Groups (CEGs) who have provided strong challenge to the Distribution Network Operators (DNOs) throughout the preparation of their Business Plans.

This report contains our feedback on the Business Plans of the six DNO groups for the period 2023-28 (ED2), published in December 2021. The groups are: Electricity North West Limited (ENWL), Northern Powergrid (NPg), Scottish Power Energy Networks (SPEN), Scottish and Southern Electricity Networks (SSEN), UK Power Networks (UKPN) and Western Power Distribution (WPD).

Our report follows on from our feedback on the draft Business Plans that were published by the DNOs in July 2021. We published letters in response to the draft Business Plans in September 2021[1]. Further detail on our role, our membership, our activities to date, and our approach to assessing the Business Plans, can be found in Appendix 1.

We have aimed to ensure that our report is, as far as is practicable, complementary to those of the CEGs, so we have not considered in any detail the companies' plans for stakeholder engagement. Our report should be considered alongside the individual CEG reports to understand how the companies have responded to views of customers and stakeholders, including regional and local government authorities, in defining outputs.

The Business Plans contain a huge amount of data and are supported by many pages of detailed justification and analysis. Even with the limits we have placed on the scope of our investigation, we have not been able to assess the entirety of the Business Plans (BPs) in the time available, though we believe that we have considered what for consumers are the most important features of the Business Plans.

The Challenge Group is independent of Ofgem. The views expressed in this Report are those of the Group and are not attributable to Ofgem, whose own assessment of the Business Plans will be reflected in its Draft and Final Determinations for RIIO-ED2.

Whilst our report has been prepared for Ofgem, we are aware that wider stakeholders (including the DNOs) may wish to consider the report, especially for the purposes of the Open Hearings on the Business Plans which will be conducted by Ofgem in March 2022.

## 1.1 Context of ED2

Ofgem have designed the RIIO-ED2 price control to support Net Zero targets while keeping the cost to existing and future consumers as low as possible, including by optimising efficiencies across the entire energy system. The price control will also need to reflect forthcoming decisions by Ofgem on access reforms.

In scrutinising the companies' plans we have taken account of a number of factors that were not present in previous price controls, and which will have a significant impact on investment in the distribution networks and their operation. In our view, the most important of these is the

[1] The response letters are available here.

transition to Net Zero, while the second is the transition from centralised network control to flexible, decentralised operation through new technologies and market mechanisms.

In addition, we are very conscious of the impact on consumers of the recent rapid rise in the cost of energy and the likelihood of high prices in future, and the consequences for affordability and fuel poverty.

These new considerations are of course additional to the historic focus on the ongoing costs of operating the networks efficiently, on ensuring resilience, on the environmental performance of the companies themselves and on their treatment of consumers in vulnerable circumstances. In this overview we offer a summary of our conclusions on each of these issues. In Section 2 of this report we give more detail on these issues across the six companies. This is followed by further detail in individual sections on each company's plan.

## 1.2 Net Zero

The most significant of the new factors is the UK's commitment to achieve Net Zero by 2050, which will require the elimination of unabated fossil fuels in electricity generation, in land transport and in space heating, all of which have implications for electricity distribution networks. There is still great uncertainty about the nature and timing of this transition to a Net Zero world:

- In electricity generation, there is uncertainty about the types of technology and the growth of distributed generation, demand response, and electricity storage facilities;
- In transport, while there is general agreement that there will be rapid growth in electric vehicles (EVs), there remains some uncertainty about its timing;
- In space heating, there are similar uncertainties about the timing of heat pump growth, and also about the split between heat pumps and hydrogen; and,
- While all these uncertainties raise the prospect of demand for network capacity increasing, there will also be downward pressure as a consequence of the use of flexibility markets, and increased network utilisation from smart control.

In consequence there is greater than usual uncertainty about the load-related network investment that will be needed over RIIO-ED2. Overall, the companies appear to have bid for an additional £1.6bn in their baseline plans compared to ED1 levels, with an additional £2.8bn potentially available through uncertainty mechanisms (UMs).

Given all these uncertainties, it is difficult to know how much investment can be accurately forecast and firmly committed in investment plans now, and how much should be subject to uncertainty mechanisms which allow spending to be adjusted in the future in response to actual demand.

In their plans, companies have taken different approaches:

- Some have put higher levels of investment into baseline expenditure, in the belief that it will be needed at some time, and the costs of investing too soon are lower than the costs of underinvestment; whilst,
- Others have proposed lower levels of baseline expenditure, in the belief that uncertainty mechanisms will work well enough to pass through the costs of any additional investment.

Both approaches carry risks that consumers will pay more than they should. If it turns out that the baseline is set too high, then companies may not spend their allowances with the consequent risk of the companies realising windfall gains. If they spend their allowances, there is a risk of stranded assets, or of missing out on cheaper flexibility solutions. If the baseline is set too low, the uncertainty mechanisms may be too slow and inaccurate, and hence compromise the Net Zero targets. Uncertainty mechanisms will need to be appropriately calibrated given there is past evidence that these have been overgenerous to companies.

But it is important to put this issue into context. For the RIIO-ED2 price control, the overall baseline load-related expenditure (LRE) that companies have bid is around 14% of overall expenditure, compared to an equivalent 8% during RIIO-ED1. Nonetheless these are large numbers and, whatever its decision, Ofgem will need to take all possible steps to ensure that this uncertain expenditure is managed efficiently for consumers.

We understand the concerns around the affordability of energy, and that, all else being equal, it is better not to incur costs before they are strictly necessary. However, the wider societal costs of the failure to achieve Net Zero are such that this is probably not an area for cutting expenditure on grounds of short-term affordability. Still, it will be important to ensure that this does not lead to excessive windfall gains for companies if the investment is not required.

## 1.3 Distributed Energy Technology, Whole System and DSOs

There have also been enormous advances in technology on many fronts. Developments in electricity generating and storage technologies are leading to changes in the nature, scale and location of generation, which will fundamentally change the pattern of how electricity flows in the network – some parts will see an increase in load, others a reduction. Meanwhile, advances in information technology (IT) have made it much easier to monitor and control the operation of electricity networks, and to create and operate markets for system services, all in real time. This has the potential to reduce significantly the costs of supplying electricity, but it requires a major paradigm shift in system operation, away from centralised control (currently the job of the DNO and for the high voltage (HV) network, National Grid Electricity System Operator (ESO)) towards decentralised decisions made by many players in real time in a world of active markets.

Ofgem has charged the DNOs with promoting this second major transition, by more actively managing their networks, including the full utilisation of flexibility resources and the use of smart technology and data. However, there is a clear conflict of interest inherent in giving the task to the network owners, since the optimum solution would almost certainly lead to a reduced requirement for network assets. This highlights the importance of Ofgem’s current work on the reform of Distribution System Operators (DSO) governance arrangements.

Not surprisingly, therefore, the plans of almost all the companies for developing their DSOs and delivering smart control, flexibility and whole system benefits could, in many areas, be more ambitious. Their total proposed DSO spend is £890m, three times the expected spend in ED1. Some of this is to expand their skills and capability, which is necessary, but there is little convincing analysis of the benefits that will flow from this expenditure. We have not felt that the companies have fully demonstrated ambition to open DSO activities to third parties. Moreover, there seem to us to be few attempts to produce a plausible strategy for whole system development, which should encompass, among other things, linkage with the HV network and with other local and national energy markets.

## 1.4 Costs and affordability

While the recent spike in international gas prices and its effect on consumer prices has made the affordability of energy a particularly important current issue, any short-term measures to reduce consumer prices are a matter for government. However, the issue does highlight the need to maintain tight control over all components of the consumer price, one of which is network costs. This control is critical to the ambition of delivering Net Zero at least cost. And a key component of network costs is the DNOs' expenditure plans, which we have scrutinised with great care.

In aggregate the DNOs propose a baseline expenditure (totex) over ED2 of some £24bn, which is 31% higher than that projected for ED1. When uncertainty-related forecasts (including for potential access reforms) are added, this increases to over £29bn, a potential 60% increase. When load related expenditure is excluded from the baseline forecast, the residual total expenditure (totex) increase is around 24% on a largely similar underlying asset base. There are valid reasons for some of this increase such as investment in DSO and smart control technology. But increases in asset health and non-operational costs appear higher than necessary, with the caveat that there are significant differences between the companies, all of which are analysed in greater detail in later sections. Overall, we do not believe that a large part of this increased spend has been adequately justified and we urge Ofgem take a close look at all these totex plans.

As well as increased baseline expenditure, the plans propose significant risk contingencies, allowing for some c.£4bn of additional costs to be passed through if uncertainty mechanisms are triggered. The use of such mechanisms will significantly decrease the risks that the companies face of overspending their revenue allowances and we believe this should be reflected in the cost of capital allowances.

## 1.5 Other outputs

Turning to outputs, we found that company plans generally were adequate but not as well justified as they could be. We have highlighted some of our views below.

**Reliability and resilience**

Storm Arwen, and its consequences, came too late to influence the sections of the plans concerned with reliability and resilience of systems. So, as it stands, perhaps the most striking feature of the reliability proposals is that they would, if translated into final targets, lead to an even wider spread among DNOs of reliability standards than now. When Ofgem sets the final reliability standards for DNOs, it will need to consider whether there are materially different levels of customer support for increased reliability which justify such a variation in standards across the regions.

Moreover, the experience of Storm Arwen is coupled with the likelihood that similar extreme weather events will, as a consequence of climate change, become more frequent in future. This means that, once Ofgem has concluded its investigation into the DNOs' response to Storm Arwen, it will need to find the right balance between improved reliability driven by traditional network reinforcement and the broader resilience needed to protect customers from the impact of these extreme weather events.

**Environmental Action Plans**

Each company produces an Environmental Action Plan (EAP), setting out how it proposes to reduce its own business carbon footprint (BCF) and its impact on the environment. Each CEG has scrutinised its associated company's EAP, and we have looked across the plans of all companies, specifically at their proposals for decarbonisation of their networks. These plans, though variable in scope and quality, are generally adequate. All the companies aspire to take a lead in this area, but some are significantly more advanced than others in looking at the emissions associated with their supply chain. Our main concern is that few companies have provided evidence that they have carefully analysed the most efficient way of meeting their targets i.e. there is little sign of effective optioneering.

**Vulnerability**

All the companies' strategies for supporting consumers in vulnerable circumstances represent a significant step up from the scale and nature of their activities in ED1. However, their targets for identifying consumers eligible to receive extra support during a power cut appear to be markedly different, implying that consumers in different areas could receive quite different levels of service. There is also little evidence that companies understand and evaluate the reach and effectiveness of their support during a power cut – nor are those DNOs that are significantly ramping up the volume of fuel poverty support yet able to provide assurance on the deliverability of their proposals. There are also questions about value for money in this area given that, on the limited evidence available, there appear to be significant differences in the costs to deliver similar benefits.

## 1.6 Consumer Value Propositions

As part of Ofgem's Business Plan Incentive, companies had the option of setting out proposals for activities which go beyond minimum requirements and beyond the functions typically undertaken by a DNO as business as usual (BAU); and which will lead to benefits to consumers. DNOs offered a total of 24 Consumer Value Propositions (CVPs); of these we do not support a CVP reward for 20 and offer partial support for the remaining 4. The main reason for rejection was an inadequate analysis of the benefits, but there were also several which seemed to us to not clearly meet the definition of going beyond a DNO's BAU functions, even if they offer some value to customers. For a few CVPs, there seemed insufficient rationale for it be a DNO to carry out the proposed activity. The four which we thought merited further consideration were proposals for developing innovative ways of supporting customers, particularly those in greatest need, and an environmental improvement project.

## 1.7 Finance

In our view all companies are financeable under Ofgem's Working Assumptions (W/As) (which include a cost of equity allowance of 4.65% and a cost of debt allowance of 2.09%), although several companies claim they would not be financeable on that. With one exception, companies have engaged at only the most minimal level with the measures Ofgem proposed to aid financeability. Not surprisingly all have rejected the concept of some form of outperformance wedge.

We were disappointed by the Competition and Market Authority's (CMA) rejection of the outperformance wedge in their recent determinations on the Transmission and Gas Distribution price controls. We remain convinced that there is ample evidence of outperformance by regulated monopolies and that measures to address their intrinsic ability to outperform their price controls is justified and necessary. We encourage Ofgem to give further thought to this issue.

## 1.8 Open hearings

In terms of further scrutiny of the plans at Ofgem's Open Hearings in March, we have highlighted a number of key topics at the start of each company chapter. In our view, the most important areas are the levels of totex proposed by the companies and the adequacy of the plans for their DSOs.

# 2. Overview and comparison

The table below summarises and compares our view of the quality of the final RIIO-ED2 Business Plans across the six companies.

The red, amber, green (RAG)[2] ratings in the following table provide an overview assessment based both on the level of ambition and the level of detailed justification contained in the companies' plans in those areas which we have examined. These ratings, as both a summary and an average rating, only provide an indication of our more detailed assessment. In some cases we have assessed that a company's plans in one of the areas we have looked at are well justified but lacking in ambition, or vice versa. We encourage all readers to refer to our full commentary in this section and the company-specific sections that follow. Our assessments and inter-company comparisons inevitably reflect the limited time available for our review. Whilst we have assigned specific numbered ratings to each area of the BPs, we have not assigned weightings to each of these elements. It would therefore be inappropriate to derive any single overall rating for each of the companies.

*Table 1: Comparative summary of quality of ED2 Business Plans*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| Track record from RIIO-ED1 | 4 | 3 | 2 | 2 | 4 | 3 |
| Scenarios and forecasts | 3 | 4 | 4 | 2 | 3 | 4 |
| Totex: LRE, incl. anticipatory investment | 4 | 2 | 4 | 3 | 4 | 4 |
| Totex: NLRE, incl. asset health | 3 | 3 | 2 | 2 | 2 | 3 |
| Totex: Network operating costs | 4 | 4 | 3 | 2 | 5 | 5 |
| Totex: Non-operational costs | 1 | 2 | 3 | 2 | 3 | 2 |
| Totex: Ongoing efficiency and RPE | 3 | 2 | 1 | 2 | 4 | 2 |
| Totex: Uncertainty mechanisms | 2 | 3 | 2 | 2 | 4 | 4 |
| Outputs: DSO and digitalisation strategy | 4 | 2 | 3 | 3 | 5 | 2 |
| Outputs: Whole system strategy | 2 | 2 | 2 | 4 | 4 | 2 |
| Outputs: EAP | 3 | 3 | 4 | 3 | 4 | 3 |
| Outputs: Vulnerability strategy | 3 | 3 | 4 | 3 | 4 | 4 |
| Outputs: Reliability | 3 | 3 | 3 | 3 | 4 | 3 |
| Finance | 2 | 3 | 3 | 3 | 4 | 2 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In this section we summarise observations from our comparative view of the plans across these key areas:

- Track record from RIIO-ED1
- Costs, scenarios and forecasts
- DSO and whole system proposals

[2] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed in Table 1; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

- Other outputs including Environmental Action Plans, vulnerability strategies and reliability
- Consumer Value Propositions
- Finance

## 2.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand the past performance and behaviour of individual DNOs and DNO Ownership groups. We also met with companies to discuss their track record and their experiences during RIIO-ED1. In examining their track records, we are seeking to understand and compare their past performance and their starting point for ED2.

In our scrutiny, we considered a wide range of factors, including how companies had enabled low-carbon technologies, DSO and flexibility initiatives, network utilisation and smart grid development, environmental plans, and customer service, including vulnerable customers and asset health. We also assessed their expenditure and financial performance.

Our overall scores for company track records are shown below:

*Table 2: Track record scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Track record from RIIO-ED1** | 4 | 3 | 2 | 2 | 4 | 3 |

### 2.1 (i) DNO output performance

We closely examined the main DNO performance incentives and rewards, namely delivery of output targets and the efficiency measures. These factors are shown in the table below using data from the DNO 2021 Regulatory Reporting Packs. The data shows actual figures for the first six years of the ED1 price control and forecasts for the final two years[3].

The table shows the main output incentives for Customer Interruptions (IIS), Broad Measure of Customer Service (BMCS), and Connections (Time to connect), and for the totex efficiency incentive. The operational Return on Regulatory Equity (RoRE) figure is also shown, which is built up from the ex-ante cost of equity and information quality incentive for each company, plus a range of incentives. The ones listed are the most significant in terms of reward.

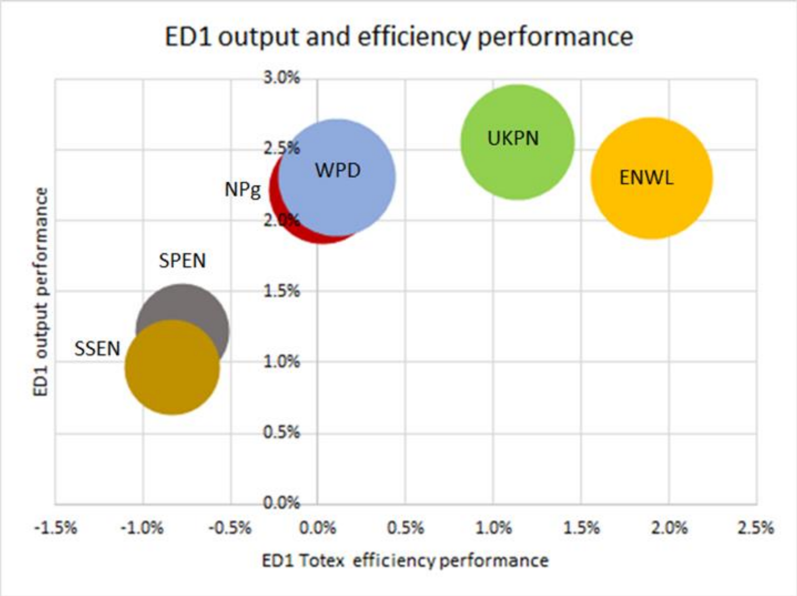
*Table 3: ED1 output and efficiency performance*

| **ED1 performance (2021 RRP)** | **ENWL** | **NPg** | **WPD** | **UKPN** | **SPEN** | **SSEN** |
|---|---|---|---|---|---|---|
| *Output incentives* | | | | | | |
| Interruptions (IIS) | 1.8% | 1.7% | 1.5% | 1.9% | 0.7% | 0.5% |
| Customer service (BMCS) | 0.3% | 0.4% | 0.6% | 0.6% | 0.5% | 0.3% |
| Time to connect (TTC) | 0.2% | 0.1% | 0.2% | 0.1% | 0.1% | 0.1% |
| **Output incentives total** | 2.3% | 2.2% | 2.3% | 2.6% | 1.2% | 1.0% |
| | | | | | | |
| **Totex efficiency incentives** | 1.9% | 0.0% | 0.1% | 1.1% | (0.8%) | (0.8%) |
| **Operational RoRE** | 10.5% | 8.0% | 9.5% | 9.2% | 6.1% | 6.2% |

[3] We have used a common published source for consistency. The data in this overall table differs slightly from the equivalent tables in the individual company chapters of this report, where some companies have advised us of adjustments to their expected outturn figures.

Using this data, we have also shown comparative performance of each company for both efficiency and output performance in the chart below. The size of the bubbles on the chart represents the RoRE percentages for each company. The operational RoRE for WPD reflects their increased returns awarded for fast tracking at the start of ED1.

*Chart 1: ED1 output and efficiency performance*




As illustrated above, the chart suggests that all companies except SSEN and SPEN have performed reasonably well against their key output performance targets. ENWL and UKPN have gained the greatest efficiency incentives over ED1.

We have also considered comparative company track records regarding stakeholder engagement and consumer vulnerability (SECV). The annual panel report for this incentive has scored each company performance during ED1 as shown below. WPD's submission for the last two years has been omitted but is expected to be included once an Ofgem investigation into WPD's Priority Service Register updating has concluded.

*Table 4: ED1 Stakeholder engagement and consumer vulnerability performance*

| | SECV panel scores | |
|---|---|---|
| | ED1 Average | 2020/21 |
| ENWL | 6.0 | 6.6 |
| NPg | 6.6 | 5 |
| WPD | n/a | n/a |
| UKPN | 7.8 | 8 |
| SPEN | 7.0 | 7.1 |
| SSEN | 6.2 | 6.2 |

We note that UKPN and SPEN appear to be consistently leading performers in this important area of performance.

### 2.1 (ii) DNO totex and efficiency performance

We have also examined totex performance over ED1.The following table uses 2021 price control financial model data to compare under- or overspend against totex allowances. The first six years are actual data and the remaining two are forecasts. We note that NPg and WPD both advise that they expect their eventual ED1 outturn to be in line with their allowances.

*Table 5: ED1 totex performance*

**ED1 - Totex (2021 PCFM)**

| £m (2012/13 prices) | ENWL | NPg | WPD | UKPN | SPEN | SSEN | Total |
|---|---|---|---|---|---|---|---|
| Totex allowance | 1860 | 3011 | 6984 | 6038 | 3229 | 3706 | 24827 |
| Totex actual/forecast | 1767 | 2981 | 6890 | 5419 | 3319 | 3710 | 24086 |
| Totex (under)/overspend £m | (93) | (30) | (94) | (619) | 91 | 4 | (741) |
| % totex (under)/overspend | (5%) | (1%) | (1%) | (10%) | 3% | 0% | (3%) |

The table shows that aggregate totex underspend is expected to be 3% or £741m. UKPN and ENWL have the highest levels of totex savings over allowance, with SPEN showing an increase over allowance.

We recognise that a common driver for these totex differences was that actual load-related capital expenditure (capex) was lower than the ED1 allowance due to a lower-than-expected take-up of low-carbon technologies (LCT) over the period. The following table shows the LRE performance against allowance, and the residual totex under/overspend once LRE is removed.

*Table 6: ED1 load-related capex and residual totex performance*

**ED1 - LRE and totex excl. LRE (2021 PCFM)** **ED1 - 8 year actual/forecast**

| £m (2012/13 prices) | ENWL | NPg | WPD | UKPN | SPEN | SSEN | Total |
|---|---|---|---|---|---|---|---|
| LRE (under)/over spend £m | (40) | (42) | (42) | (438) | (37) | (105) | (704) |
| % LRE (under)/over spend | (31%) | (19%) | (7%) | (44%) | (12%) | (25%) | (26%) |
| Totex (excl. LRE) (under)/overspend | (53) | 12 | (51) | (180) | 128 | 108 | (36) |
| % Totex (excl. LRE) (under)/overspend | (3%) | 0% | (1%) | (3%) | 4% | 3% | 5% |

### 2.1 (iii) Load-related costs

All companies experienced falling demand and fewer LCT connections (especially heat pumps) than planned during ED1. But we found it difficult to assess what this meant for the network capacity headroom that was available at the start of ED2.

All companies appear to be underspending their LRE allowance, with UKPN underspending by 44% and ENWL by 31%. Underspending on LRE allowances during ED1 raises concerns that this expenditure has been deferred and these funding requirements may be duplicated in ED2.

### 2.1 (iv) Other costs

Table 6 also shows that, after the removal of LRE costs, aggregated totex rose by 5%. ENWL and UKPN are showing the largest underlying efficiency savings and SPEN and SSEN are showing underlying cost increases. WPD and NPg have delivered their allowed totex in full with LRE reductions being offset by increases elsewhere.

We note for asset health and non-load-related capex that all companies appear on track to meet their Network Asset Risk Metrics (NARMs) asset health targets for the end of ED1. For DSO/whole system, while some good examples of progress have been presented, it has been difficult to assess overall progress during ED1 for smart grid/DSO/network visibility expenditure, or benefits realised. We are concerned that some IT expenditure may have been deferred to ED2.

In our discussions with companies, we note that some disputed that there was an equivalent starting point for ED2, particularly as WPD was fast-tracked. However, we consider that all companies have had an 8-year period to perform against allowances and output targets, whether they agree with them or not.

Overall, taking the above factors into account we consider that UKPN and ENWL appear to have demonstrated the best performance during ED1, demonstrating both good output performance and efficiency savings. SPEN and SSEN were the weakest performers, with the weakest output performance and efficiency savings.

## 2.2 Costs, scenarios and forecasts

### 2.2 (i) Scenarios and forecasts

In December 2020, the Committee on Climate Change announced the 6th Carbon Budget in which they recommended that 60% of the necessary emissions reduction to 2050 will need to be achieved in the next 15 years. Additionally, the UK Government's 2021 Net Zero Strategy and its 2020 10 Point Plan for a Green Industrial Revolution sets out the steps they are taking to support the continued decarbonisation of power, the electrification of transport and the transition to low-carbon energy sources for heat.

Although binding commitments to meeting the Net Zero target have been made, there remain different pathways that could be taken. Some aspects are more certain – for example the transition to electric vehicles instead of petrol and diesel cars and vans, in response to the Government's announcement to end sales of new combustion engine vehicles by 2030. Other aspects are less certain – in particular, how our homes will be heated. Although the UK Government's 10-point plan is targeting a rollout of 600,000 heat pumps a year by 2028, there is still a high degree of uncertainty about the extent to which electricity will be the prime source of heating for most homes, and how much improvement there will be in the energy efficiency of properties. These developments will increase overall electricity consumption, but the growth profile of these technologies is uncertain, and consumption increases will also be offset by consumer energy efficiency initiatives.

Ofgem's Business Plan Guidance (BPG), issued in April 2021[4], sets out how the DNOs should take account of these uncertainties in their Business Plans. DNO investment plans should therefore be based, as far as is practicable, on well-informed and justified forecasts of demand and generation growth. DNOs should be able to demonstrate that their forecasts have been informed by the range of assumptions found in the Net Zero compliant energy pathways in the Electricity System Operator's Future Energy Scenarios, and the Climate Change Committee's 6th Carbon Budget.

Taking into account these pathways and scenarios, each DNO needs to develop its own scenarios that are suitable for its own networks and geographical areas. In developing these scenarios, DNOs should engage with local stakeholders to understand what trajectory for decarbonisation is likely to be followed in that area.

In our review of DNO plans, we looked for evidence that the companies had considered a wide range of scenarios which were consistent with Net Zero objectives, had developed demand forecasts which followed logically from these scenarios, and that these demand forecasts were consistent with forecasts for low-carbon technology uptake. Our scores for the companies are shown below:

[4] This document is available here.

*Table 7: Scenarios and forecasts scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| Scenarios and forecasts | 3 | 4 | 4 | 2 | 3 | 4 |

***Comparison of scenarios considered***

The Challenge Group found that the companies used a variety of scenarios, and these translated into different investment forecasts and variations to load-related expenditure that are addressed through uncertainty mechanisms. All of the scenarios appear to be consistent with Net Zero objectives.

Company forecasts for the growth of electric vehicles and heat pumps are key drivers of future demand growth. The table shows their 'Best views' for numbers of these LCTs by 2028, together with their 'Upper views' from their planning scenarios.[5] We have also compared these forecast volumes with each DNO's customer numbers to compare penetration of these technologies.

*Table 8: Comparison of DNO forecast for EV and heat pump uptake*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| ENWL | 638 | 26% | 79 | 3% | 699 | 28% | 638 | 26% |
| NPg | 941 | 24% | 309 | 8% | 1139 | 28% | 334 | 8% |
| WPD | 2079 | 25% | 893 | 11% | 2744 | 34% | 1522 | 19% |
| UKPN | 2637 | 30% | 278 | 3% | 2729 | 31% | 612 | 7% |
| SPEN | 674 | 19% | 366 | 10% | 1027 | 29% | 808 | 23% |
| SSEN | 994 | 24% | 512 | 13% | 1300 | 32% | 800 | 20% |
| Total | 7963 | 26% | 2437 | 8% | 9638 | 31% | 4714 | 15% |

Overall, the total number of EVs and heat pumps is consistent with the numbers forecast in the Consumer Transformation scenario of the ESO 2021 Future Energy Scenarios, which anticipates 8.4m EVs and 2.4m heat pumps connected by 2028.

For most companies, the scenarios considered remain broadly the same as the draft plans submitted in July. We note that companies have relatively similar views about the future take-up by customers of electric vehicles but that estimates for heat pumps vary more widely.

In particular, ENWL and UKPN appear to have expectations that low percentages of heat pumps will be installed in their regions, explained by affordability/high levels of gas heating for ENWL and heat network substitution for UKPN. We anticipate that heat pump rollout is likely to be a stronger driver of peak demand growth and the need for network capacity increases than electric vehicles. This is because many electric vehicle owners may seek to charge their vehicles more cheaply during off-peak periods. This low forecast may be expected to also result in a below-average forecast for load-related expenditure growth.

***Comparison of demand forecasts***

The table below shows the companies' peak demand forecasts as stated in their Business Plan Data Tables (BPDT).

[5] Heat pump and EV numbers presented in company strategic summary submissions. Some numbers differ from those presented elsewhere in plans.

*Table 9: Comparison of DNO peak demand forecasts (MW)*

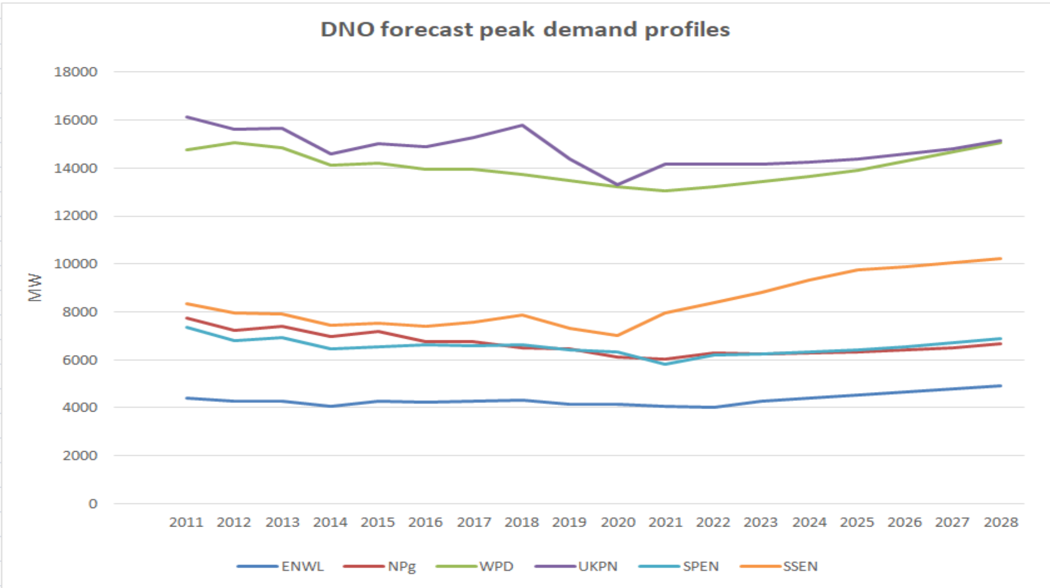
| Peak Demand MW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | Change 2020-8 |
|---|---|---|---|---|---|---|---|---|---|---|
| ENWL | 4,140 | 4,049 | 4,016 | 4,280 | 4,408 | 4,545 | 4,657 | 4,776 | 4,899 | 18% |
| NPg | 6,108 | 6,006 | 6,296 | 6,259 | 6,276 | 6,325 | 6,405 | 6,516 | 6,662 | 9% |
| WPD | 13,237 | 13,062 | 13,202 | 13,423 | 13,642 | 13,920 | 14,306 | 14,671 | 15,079 | 14% |
| UKPN | 13,316 | 14,169 | 14,177 | 14,184 | 14,268 | 14,386 | 14,579 | 14,814 | 15,138 | 14% |
| SPEN | 6,313 | 5,806 | 6,185 | 6,259 | 6,331 | 6,426 | 6,531 | 6,697 | 6,871 | 9% |
| SSEN | 7,001 | 7,950 | 8,376 | 8,820 | 9,323 | 9,737 | 9,890 | 10,060 | 10,223 | 46% |
| Total | 50,115 | 51,042 | 52,251 | 53,225 | 54,248 | 55,339 | 56,369 | 57,534 | 58,872 | 17% |

The table shows an overall peak demand increase from 50GW in 2020 (albeit that demand is reduced by Covid in this year) to 59GW in 2028, a 17% increase overall. However, it is noticeable that SSEN have forecast a 46% increase over this period which seems out of step with other DNOs and national forecasts.

We have also examined peak demand change over a longer time horizon. The following chart plots DNO peak demands from 2011 through to 2028. It shows that peak demand on DNO networks was 59GW before falling to current levels. The forecast peak demand growth suggests that the 2011 peak demand will not be reached before 2028.

While peak demand is an important driver of the need for DNO network investment, we recognise that future distribution network capacity constraints will emerge on low voltage (LV) secondary networks so there will not necessarily be a direct relationship between peak demand and investment needs.

*Chart 2: DNOs' actual and peak demand forecasts*




We compared the DNOs' demand forecast with those in the ESO's Future Energy Scenarios, noting that the total peak demand differs due to large loads that are directly connected to the transmission system, such as heavy industry, the rail network and power stations.

*Table 10: Comparison of ESO FES2021 ACS peak demand forecasts (GW)*

| Electricity System ACS Peak Demand GW | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | Change 20-28 |
|---|---|---|---|---|---|---|---|---|---|---|
| FES 2021 Consumer Transformation | 58.2 | 57.5 | 57.4 | 57.7 | 58.6 | 59.8 | 60.8 | 62.3 | 64.5 | 11% |
| FES 2021System Transformation | 58.2 | 58.3 | 58.5 | 58.7 | 59.1 | 59.7 | 60.3 | 61.1 | 62.2 | 7% |
| FES 2021 Leading the Way | 58.2 | 56 | 55 | 55.1 | 55.9 | 57.2 | 58.5 | 60.4 | 62.6 | 8% |
| FES 2021 Steady Progression | 58.2 | 59 | 60.2 | 61.3 | 62.3 | 63.3 | 63.9 | 64.8 | 65.8 | 13% |

The increase in demand between 2020 and 2028 are within the range expected by the ESO Future Energy Scenario (FES) scenarios for five of the six DNOs. However, the forecasts submitted by SSEN are higher than expected and not fully explained in their Business Plans and appear to be anomalous with other DNOs' forecasts. Whilst we recognise that 2020 was subject to various lockdowns due to the pandemic, SSEN has not adequately justified this large demand increase.

In addition, we note that peak demand on DNO networks is still falling and is unlikely to reach historic levels until 2028 or beyond. While peak demand may not be fully representative of the expenditure needs on low voltage networks, we would expect DNOs to clearly demonstrate how they use their lower voltage demand and utilisation profiles to justify additional investments.

Overall, we welcome the considerable efforts made by all companies to develop consistent scenarios. We considered that NPg, SPEN, and WPD had provided the strongest scenarios and forecasts. We noted that UKPN and ENWL 'Best view' forecasts for numbers of heat pumps appear below average and we are concerned both that these levels may be lower than expected, and that these lower levels are not reflected in their peak demand forecasts. We note that UKPN identified local factors such as heat networks substituting for heat pumps, and that ENWL have identified local affordability issues, but in our view we do not consider that this fully explains their lower LCT or inconsistency with peak-demand forecasts. We considered the SSEN forecasting of peak demand to be unduly high without sufficient evidence to show why this should be the case.

### 2.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, consideration of options, and cost profiling; and,
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages. We have scrutinised and provided scores for individual elements of the totex submissions in the remainder of this section.

We have examined the following major totex cost categories in aggregate across all DNOs and how they are proposed to change between ED1 and ED2, as shown in the table below.

*Table 11: Comparison of ED1 and ED2 totex categories*

| ` | % of totex | |
|---|---|---|
| | ED1 | ED2 |
| Total load related capex | 8% | 14% |
| Total non-load related capex | 31% | 32% |
| Total network operating costs | 23% | 19% |
| Total non operational costs | 38% | 36% |

We note that load-related capex forecasts increase from 8% to 14% of the total baseline totex, and non-load capex comprises 32%, with network operating costs at 19% and non-operational costs at 36%. While baseline load-related costs are significant, they still make up a relatively small proportion of total expenditure.

The average ED2 totex for each DNO and percentage change from ED1 average totex are set out in the following table[6]. The table shows the breakdown of changes in the main capex and operational expenditure (opex) categories together with adjustments that include the impact of assumptions for ongoing efficiency and real price effects upon baseline totex so that each company may be compared on an equivalent basis. The resultant baseline totex (after adjustments) combined across all DNOs shows a totex increase of 31% for ED2 from ED1, totalling some £24bn for the period.

*Table 12: Overall totex comparison (and % change from ED1)*

| | ENWL | | NPg | | WPD | | UKPN | | SPEN | | SSEN | | ED2 Total Totex (£m) | ED2 Total Annual Totex (£m) | Overall ED1 - ED2 change (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual average Totex (£m) | ED2 | % change | ED2 | % change | ED2 | % change | ED2 | % change | ED2 | % change | ED2 | % change | | | |
| Total load related capex | 33 | 94% | 90 | 245% | 201 | 113% | 117 | 52% | 89 | 94% | 102 | 144% | 3158 | 632 | 109% |
| Total non-load related capex | 112 | 28% | 198 | 20% | 415 | 24% | 279 | 39% | 236 | 32% | 264 | 68% | 7524 | 1505 | 34% |
| Total Network Operating Costs | 61 | 6% | 122 | 2% | 227 | -6% | 201 | -6% | 109 | 11% | 147 | 21% | 4335 | 867 | 2% |
| Total non operational costs | 134.8 | 36% | 184 | 21% | 463 | 20% | 370 | 12% | 220 | 13% | 290 | 27% | 8311 | 1662 | 19% |
| Baseline totex | 340 | 30% | 594 | 28% | 1307 | 24% | 967 | 17% | 654 | 26% | 804 | 46% | 23328 | 4666 | 27% |
| Adjustments (OE/RPE) | 10 | | 23 | | 34 | | 1 | | 47 | | 19 | | | | |
| Baseline totex after OE/RPEadjust. | 350 | 34% | 617 | 36% | 1341 | 27% | 967 | 17% | 701 | 35% | 822 | 50% | 23998 | 4800 | 31% |
| Uncertainty mechanisms | 46 | | 46 | | 260 | | 186 | | 49 | | 210 | | 3977 | 795 | |
| Totex Incl UM's | 396.2 | 52% | 663 | 46% | 1601 | 51% | 1153 | 40% | 750 | 45% | 1032 | 88% | 27975 | 5595 | 53% |
| Totex incl UM's and Access | 432 | 65% | 705 | 55% | 1662 | 57% | 1185 | 44% | 813 | 57% | 1038 | 89% | 29177 | 5835 | 59% |

The table also shows the overall impact of uncertainty mechanisms for ED2, potentially adding another £4bn if the uncertainty events all occur. If DNO estimates of £1.2bn are added for the potential forthcoming access reforms, then the total may reach more than £29bn, an increase of 60% or around £11bn over the equivalent ED1 totex run rate of £17.8bn over five years.

Our observations from comparing individual DNOs are that SSEN and UKPN show the lowest baseline totex increases whilst ENWL, NPg and SPEN show the highest. In our draft Business Plan feedback, we expressed concern that the proposed large increases were unjustified and invited all companies to consider cost reductions. In the final Business Plan, we note that ENWL's baseline bid has decreased, which is welcome, but that UKPN's has increased. Others have remained much the same as before.

Overall, the company totex forecasts demonstrate a potentially major increase from ED1 levels of expenditure, and while increases may be expected in load-related expenditure and in investments in DSO initiatives, we are concerned that the overall increase is much higher than might be expected. We also note that DNOs appear to have identified more than £1bn of totex

[6] Note: These totex figures exclude 'other costs outside the price control' The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms

savings in aggregate during ED2 because of their DSO initiatives for smart system control and flexibility. But we have found it difficult to ascertain if these savings have been applied.

In broad terms, we consider that there are three major totex upward cost drivers for ED2, namely for load-related capex, DSO expenditure, and access reform expenditure (if this proceeds), and a major downward cost driver from DSO savings. The companies' forecast baseline increases over ED1 levels for these additional items total about £1.6bn for load-related capex, and about £0.6bn for DSO, totalling some £2.2bn. Even if all these increases were allowed without additional potential savings from DSO initiatives, this would result in an overall increase from the ED1 equivalent expenditure level of £17.8bn to around £20bn for ED2, about 20% lower than the £24bn baseline which the companies are bidding for in aggregate before uncertainty mechanisms.

Based on these assumptions, aggregate DNO bids for a 20% increase in underlying totex (before non-load uncertainty mechanisms) for ED2 appear questionable given their stable underlying business characteristics. Company bids for totex increases should be given careful scrutiny by Ofgem.

We have considered each of the major cost categories in more detail, below, and in the respective company chapters.

### *ii.a. Totex: Load-related expenditure, incl. anticipatory investment*

The ED2 period comes at a critical time for the energy transition – the growth in distributed low-carbon technologies is expected to grow dramatically through to 2050 and DNOs will need to respond to make sure their network can enable this transition as efficiently as possible. In our assessment of load-related capex, we have considered the following:

- Whether robust energy scenarios and associated network utilisation data support the investment plans on primary and secondary networks;
- Whether the plans have robust Engineering Justification Proposal (EJPs) and cost-benefit analysis (CBAs), which consider alternative reinforcement options, and demonstrate efficient costs and volumes;
- Whether a 'one touch' strategy has been adopted such that anticipatory investment, e.g. higher capacity cables, is included in investment plans; and,
- Whether capex plans include savings from flexibility and smart grid initiatives.

The scores derived from our scrutiny of company plans is shown below:

*Table 13: Load-related capex scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: LRE, incl. anticipatory investment** | 4 | 2 | 4 | 3 | 4 | 4 |

The following table provides a breakdown of load-related capex across DNOs. It shows average annual reinforcement across primary and secondary networks, together with other load-related capex (including price control connections and fault level reinforcement). Overall, across all DNOs, there is a 109% forecast increase in load-related capex over the equivalent ED1 levels. This increase results in baseline load-related capex for ED2 rising to 14% of baseline totex compared to 8% of (an albeit lower) equivalent 5-year average totex for ED1.

*Table 14: Load-related capex comparison*

| | ENWL | | NPg | | WPD | | UKPN | | SPEN | | SSEN | | | ED2 Total | Overall ED1- |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ED2 | % | ED2 | % | ED2 | % | ED2 | % | ED2 | % | ED2 | % | ED2 Total | Annual | ED2 % |
| **Annual average Totex (£m)** | **£m** | **change** | **£m** | **change** | **£m** | **change** | **£m** | **change** | **£m** | **change** | **£m** | **change** | **Totex** | **Totex (£m)** | **change** |
| **Capex - Load related** | | | | | | | | | | | | | | | |
| Reinforcement (Primary Network) | 4 | *-39%* | 13 | *1122%* | 52 | *60%* | 34 | *-19%* | 21 | *-16%* | 31 | *65%* | 778 | 156 | *23%* |
| Reinforcement (Secondary Network) | 12 | *194%* | 51 | *194%* | 75 | *172%* | 35 | *168%* | 44 | *431%* | 5 | *64%* | 1114 | 223 | *202%* |
| Other load related capex | 17 | *161%* | 25 | *241%* | 74 | *115%* | 47 | *116%* | 23 | *93%* | 66 | *231%* | 1265 | 253 | *147%* |
| *UM adjustment* | | | | | | | | | | | | | | | |
| **Total load related capex** | 33 | *94%* | 90 | *245%* | 201 | *113%* | 117 | *52%* | 89 | *94%* | 102 | *144%* | 3158 | 632 | *109%* |

Overall, the main increases are shown in secondary networks, connections within the price control, and in fault level reinforcement. The largest increase in load-related totex is presented by NPg with a 245% increase from the ED1 average, and the least by UKPN with a 52% increase.

The most significant increases are in secondary network reinforcement. We recognise that DNOs will need to prioritise this expenditure – for example, for service unlooping and upgrade of fuses that is needed to enable the connection of low-carbon technologies.

With respect to the justification for the increased expenditure, we would make the following general observations:

- **Lack of visibility about future network capacity needs –** all companies have developed detailed scenarios to identify potential increased demand and need for reinforcement on their networks. However, we found it difficult to assess the existing capacity headroom that these scenarios were building on. We are concerned that data showing actual network utilisation and consumer consumption may be limited, perhaps due to limited penetration of LV metering and smart meters, placing greater reliance on modelling assumptions, rather than actual data.
- **EJPs and CBA –** we welcomed the detailed EJP analysis that had been performed by all companies, but similarly are concerned that they may be based on uncertain need case assumptions. Overall, we found both the EJPs and the CBAs to be relatively generic and therefore providing limited additional confidence that the investment was justified.
- **Anticipatory investment –** we welcome that most companies indicated that they would be applying a ‘one touch’ approach in their investment plans. However, we are concerned that potentially bringing forward potential ED3 investment, e.g. as suggested by NPg, risks both undertaking nugatory investment or undermines the potential to exploit cheaper alternatives from flexibility or smart control solutions.
- **Flexibility and smart grid –** we have provided our views in our DSO section. Overall, we are concerned that the potential reinforcement saving arising from these initiatives have not been reflected in load-related capex forecasts, and that advancing reinforcement expenditure may restrict cheaper flexibility or smart control solutions.

We suggest that Ofgem should scrutinise these issues further to seek confidence in the link between demand forecasts and the proposed investment.

Despite the above potential weaknesses, we recognise the challenges that the companies face in forecasting load-related expenditure for an uncertain period. It will be important to strike the right balance between enabling Net Zero and keeping customer bills as low as possible. As such, we suggest that full use should be made of load-related capex uncertainty mechanisms for all companies such that well-justified minimum baselines may be flexed upwards during ED2 as needed. We suggest that this would be alongside the use of price control deliverables to ensure that the baseline investment is delivered.

We consider that the strongest performers in terms of justifying their LRE forecasts are ENWL, WPD, SPEN and UKPN. While they are forecasting increases to baseline forecasts of up to around 100%, we consider these have been reasonably well justified. The SSEN baseline shows an increase of 144% which we are concerned may be higher than necessary given that uncertainty mechanisms are expected to be applied. We have concerns about the NPg forecast of 245%, which seeks to target early expenditure for ED3, which runs the risk of not being the most efficient approach.

Overall, for all companies we are concerned that there may be cost forecasts that are inefficiently included in both baseline and uncertainty bids, and that some baseline bids are at a higher than necessary level. But it will also be important to strike the right balance so that efficient investment to enable Net Zero is incentivised.

### *ii.b. Totex: Non-load-related expenditure, incl. asset health*

For non-load-related expenditure, we have compared the ED2 levels of expenditure with their ED1 equivalents, as the asset base served by these costs will remain similar. We have considered evidence for upward and downward cost drivers.

For asset replacement and refurbishment, we have considered the need case made for these interventions, together with evidence to support the proposed costs and volumes. We have examined the projected progress against the NARMs methodology for asset risk reduction over ED2. Our scores for non-load expenditure are shown below:

*Table 15: Non-load capex scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: NLRE, incl. asset health** | 3 | 3 | 2 | 2 | 2 | 3 |

The following table shows the main asset replacement costs and other non-load capex costs for each company and the sector. This cost area comprises around 32% of total DNO forecast totex for ED2 and so it is a significant cost area. Overall, there is a 36% increase proposed over the ED2 period compared to the equivalent ED1 expenditure levels.

*Table 16: Overall non-load capex comparison*

| | ENWL | | NPg | | WPD | | UKPN | | SPEN | | SSEN | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Annual average Totex (£m)** | **ED2 £m** | **% change** | **ED2 £m** | **% change** | **ED2 £m** | **% change** | **ED2 £m** | **% change** | **ED2 £m** | **% change** | **ED2 £m** | **% change** | **ED2 Total Totex** | **ED2 Total Annual Totex (£m)** | **Overall ED1-ED2 % change** |
| **Capex - Non Load related** | | | | | | | | | | | | | | | |
| Asset Replacement | 49 | *19%* | 105 | *6%* | 228 | *15%* | 142 | *45%* | 104 | *18%* | 106 | *16%* | 3665 | 733 | *19%* |
| Refurbishment | 11 | *29%* | 14 | *-6%* | 28 | *18%* | 7 | *-2%* | 13 | *12%* | 15 | *50%* | 435 | 87 | *16%* |
| Other NLRE | 52 | *37%* | 80 | *54%* | 160 | *41%* | 131 | *35%* | 119 | *50%* | 143 | *156%* | 3423 | 685 | *57%* |
| *UM adjustment* | | | | | | | | | | | | | | | |
| **Total non-load related capex** | 112 | *28%* | 198 | *20%* | 415 | *24%* | 279 | *39%* | 236 | *32%* | 264 | *68%* | 7524 | 1505 | *34%* |

SSEN has the highest increase of 68% from ED1 equivalent levels. We note that this includes significant additional expenditure including to improve Scottish Island resilience for example. In addition to these baseline forecasts, SSEN is proposing further island resilience expenditure through uncertainty mechanisms. We are concerned that this additional expenditure has not fully considered options for non-network, or non-DNO solutions and SSEN investment plans may inhibit distributed energy alternatives.

The overall increases for other companies range from 24% to 39%, which appears high given that the asset base remains largely similar. All companies expect to achieve their ED1 asset health targets. We recognise that there are some upwards cost drivers arising from network monitoring and IT, and from issues such as increased need for PCB removal.

The most significant item in non-load capex is asset replacement expenditure comprising about half of the costs. This element shows a 19% overall increase with, NPg showing an increase of 6% compared to 45% by UKPN. Other companies show increases of between 15% and 19%.

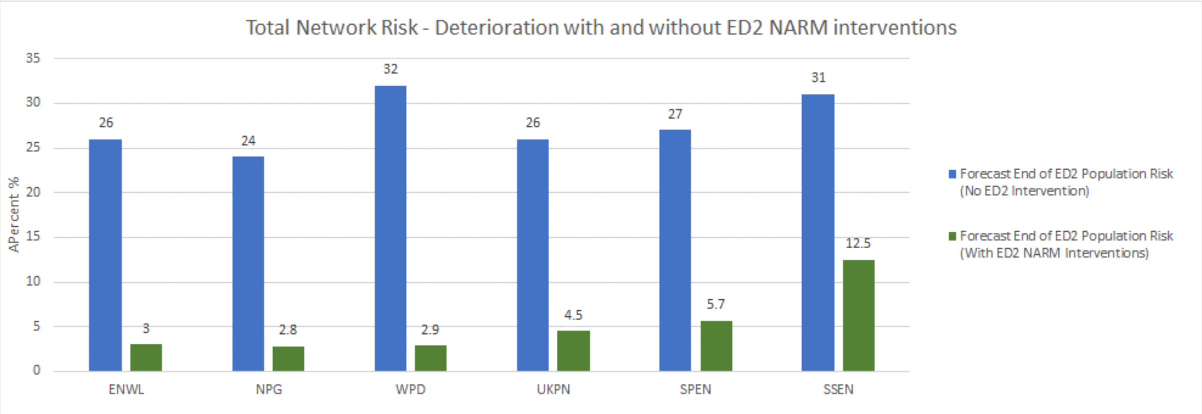
*Asset health*

We have looked specifically at the NARMs asset health proposals from the companies. The NARMs methodology covers around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs.

The following chart shows the percentage of overall network risk for NARM-related assets over ED2 both without intervention and with intervention. It shows that all companies are forecasting an increase in network risk to between 24% and 32% before mitigation.

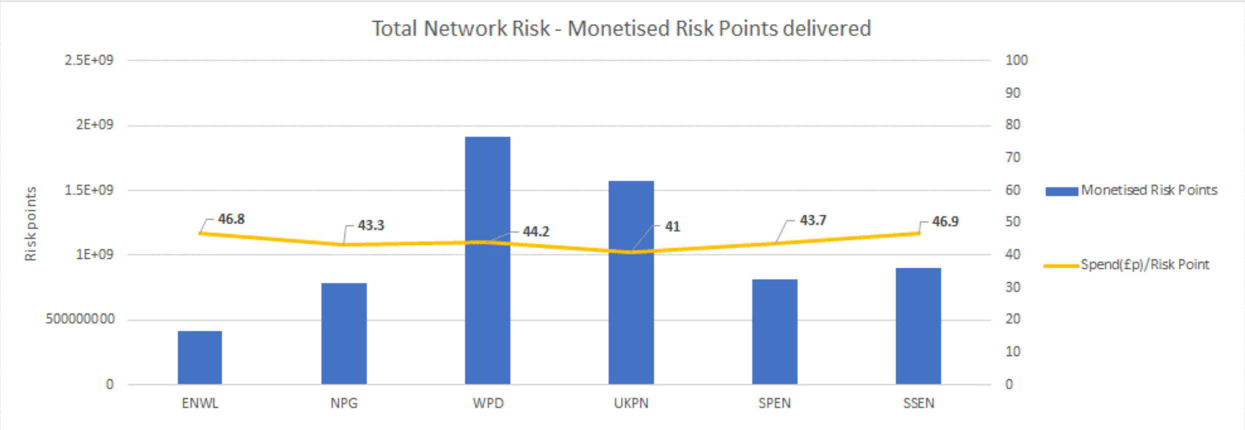
Once mitigation through asset replacement or refurbishment is taken into account, this percentage falls to a network risk of around 3% for ENWL, NPg and WPD. UKPN and SPEN show slightly higher figures but SSEN is forecasting a figure of 12.5%, which potentially will result in their network having a significantly higher health risk.

*Chart 3: ED2 total network risk comparison*




The following chart shows the monetised risk reduction (in pence per risk point) of delivering the billions of risk points that each DNO is forecasting to deliver. UKPN appears to be the most efficient DNO group with SSEN and ENWL being the highest.

*Chart 4: ED2 Monetised risk point comparison*



Taking these two charts together, it would appear that SSEN not only has a lower risk reduction forecast, but also has the highest delivery cost.

We consider that the NARMs data should provide a useful indicator of the asset health plans for the ED2 period and we welcome that most companies are seeking to ensure that robust asset health is maintained. However, we are concerned that SSEN appears to have set lower asset health targets than other companies.

Overall, we consider that all companies appear to have shown significant increases in non-load-related expenditure with increases of between 24% and 68%. While there are some cost increases in this area for issues such as DSO, IT & Telecoms and PCB removal, we do not consider that evidence has been provided for the considerable increases proposed, given a largely similar asset base with a similar asset health profile to ED1.

We have compared DNO plans for low voltage wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets.

We have summarised the proposals of all DNOs in the table below. We have compared the replacement rates over the last two price controls.

*Table 17: LV pole replacement rates*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| **NPg** | 2638 | 987 | 4097 | -62% | 315% |
| **ENWL** | 1047 | 528 | 1400 | -49% | 165% |
| **WPD** | 6568 | 7566 | 7930 | 15% | 4% |
| **UKPN** | 3471 | 4284 | 7480 | 23% | 74% |
| **SPEN** | 5259 | 1527 | 2431 | -70% | 59% |
| **SSEN** | 4657 | 2876 | 3054 | -38% | 6% |

We note that NPg is showing a planned volume increase for ED2 of over three times compared with ED1, and ENWL an increase of more than 160%. UKPN and SPEN are also showing significant increases. We have examined the associated EJPs provided by these companies, but limited evidence is provided to justify these investments and we do not consider that this step change has been justified. Volume increases proposed by WPD and SSEN appear to follow historic trends more closely.

We also observe that NPg, ENWL and SPEN appear to have significantly reduced their replacement volumes and expenditure on LV wood poles during ED1 compared to the Distribution Price Control Review 5 period, and are now forecasting increases for ED2. This suggests that investment in asset health may have been inefficiently deferred, or that forecasts for ED2 may be overstated. Based on this concerning example, we suggest that Ofgem should assess a wide range of asset replacement proposals in more detail prior to decisions on totex and risk allowances.

Overall, across all aspects of non-load capex, taking evidence for upwards and downward cost drivers into account, we do not consider any company to have fully justified expenditure increases and to be a particularly strong performer, but UKPN, SPEN, and SSEN showed the highest cost increases. Given the scale of increases proposed in this area, we suggest that Ofgem should closely examine why there should be any increase from ED1 levels.

### *ii.c. Totex: Operating costs*

In assessing network operating costs, we have compared the ED2 levels of expenditure with their ED1 equivalent expenditure rates, as the asset base served by these costs will remain similar. We have assessed evidence for upwards and downwards cost drivers. Our scores are shown below:

*Table 18: Network operating cost scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: Network operating costs** | 4 | 4 | 3 | 2 | 5 | 5 |

The following table shows the main network operating costs for each company and the sector. This cost area comprises around 19% of total DNO forecast totex for ED2.

*Table 19: Overall network operating cost comparison*

| | ENWL | | NPg | | WPD | | UKPN | | SPEN | | SSEN | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual average Totex (£m) | ED2 £m | % change | ED2 £m | % change | ED2 £m | % change | ED2 £m | % change | ED2 £m | % change | ED2 £m | % change | ED2 Total Totex | ED2 Total Annual Totex (£m) | Overall ED1-ED2 % change |
| **Opex - Network Operating Costs** | | | | | | | | | | | | | | | |
| Faults (see note 1) | 35 | *0%* | 82 | *-2%* | 116 | *-10%* | 133 | *-9%* | 61 | *10%* | 67 | *8%* | 2474 | 495 | *-3%* |
| Maintenance (see note 2) | 21 | *31%* | 35 | *22%* | 97 | *1%* | 60 | *11%* | 39 | *13%* | 69 | *45%* | 1601 | 320 | *16%* |
| Other operating costs | 5 | *-25%* | 5 | *-28%* | 14 | *-18%* | 9 | *-42%* | 9 | *5%* | 11 | *-9%* | 260 | 52 | *-21%* |
| **Total Network Operating Costs** | 61 | *6%* | 122 | *2%* | 227 | *-6%* | 201 | *-6%* | 109 | *11%* | 147 | *21%* | 4335 | 867 | *2%* |

**Note 1:** *Faults - includes Faults, ONI and 1 in 20.*
**Note 2**: *Maintenance - includes I&M and tree cutting.*

We note that WPD and UKPN both show a decrease of 6% in these costs which is welcome, especially as both companies are proposing acceptable reliability targets. SSEN and SPEN propose increases of 21% and 11% respectively; we are concerned that their proposed increases are unjustified.

Overall, we welcome that WPD and UKPN can reduce costs in this area while still committing to deliver good levels of reliability and customer service. NPg and ENWL also appear to have kept control of potential cost increases. SPEN and SSEN appear to be outliers in forecasting higher increases in this area.

### *ii.d. Totex: Non-operational costs*

In assessing non-operational costs, we have compared the ED2 levels of expenditure with their ED1 equivalent expenditure rates, as the asset base served by these costs will remain similar. We have assessed evidence for upwards and downwards cost drivers. Our scores are shown below:

*Table 20: Non-operational cost scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: Non-operational costs** | 1 | 2 | 3 | 2 | 3 | 2 |

The following table shows the main non-operational costs, both opex and capex, for each company and the sector. This cost area comprises around 36% of total DNO forecast totex for ED2 so it is the largest area in our assessment. Overall, there is a 19% increase proposed over the ED2 period compared to the equivalent ED1 expenditure levels.

*Table 21: Overall non-operational cost comparison*

| Annual average Totex (£m) | ENWL ED2 £m | ENWL % change | NPg ED2 £m | NPg % change | WPD ED2 £m | WPD % change | UKPN ED2 £m | UKPN % change | SPEN ED2 £m | SPEN % change | SSEN ED2 £m | SSEN % change | ED2 Total Totex | ED2 Total Annual Totex (£m) | Overall ED1-ED2 % change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Non-operational costs** | | | | | | | | | | | | | | | |
| Business support costs | 47 | *30%* | 54 | *11%* | 138 | *40%* | 97 | *8%* | 66 | *-5%* | 90 | *27%* | 2453 | 491 | *19%* |
| Closely associated indirects | 70 | *34%* | 100 | *18%* | 234 | *-1%* | 215 | *5%* | 121 | *7%* | 156 | *19%* | 4482 | 896 | *9%* |
| Non-operational capex | 19 | *60%* | 30 | *57%* | 91 | *78%* | 58 | *59%* | 33 | *167%* | 44 | *70%* | 1376 | 275 | *75%* |
| **Total non operational costs** | 135 | *36%* | 184 | *21%* | 463 | *20%* | 370 | *12%* | 220 | *13%* | 290 | *27%* | 8311 | 1662 | *19%* |

We note that some companies such as UKPN and SPEN are proposing increases of around 12%, while ENWL is proposing a 36% increase. These significant variations between companies and the change between ED1 and ED2, do not appear to be fully explained by the evidence provided. We note that network operating cost forecasts have remained relatively constant between ED1 and ED2, but these non-operational costs have significantly increased for the same asset base.

We recognise that there will be upward cost drivers to recognise increased load-related expenditure support, and to support the development of DSOs. But, even after taking these into account, we do not think any of the companies have justified such large increases or fully reflected downward cost drivers such as digitalisation. We consider that ENWL is the weakest performer in this area as a result of their 36% forecast increase. UKPN and SPEN are forecasting the lowest increases.

### *ii.e. Totex: Ongoing efficiency and RPE*

The companies are also required to submit proposals for their individual ongoing efficiency (OE) challenges and real price effects (RPE) over and above inflation. These should be over and above the embedded efficiencies and costs already captured in their plans.

We have assessed the company submission in terms of net value for money to consumers, after these efficiency and real price effects are combined. Our scores are shown below:

*Table 22: Ongoing efficiency and RPE scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: Ongoing efficiency and RPE** | 3 | 2 | 1 | 2 | 4 | 2 |

The company submissions are shown in the table below. RPE and OE costs are taken from company business plan data table submissions and overall percentage savings are calculated as a percentage of baseline totex.

*Table 23: Overall RPE and efficiency comparison across DNOs*

| | Real Price effects £m RPE | Real Price effects % of totex | Ongoing efficiency £m OE | Ongoing efficiency % of totex | ED2 Totex (£m) |
|---|---|---|---|---|---|
| ENWL | 84 | 4.9% | 50 | 2.9% | 1701 |
| NPg | 200 | 6.7% | 45 | 1.5% | 2970 |
| WPD | 310 | 4.8% | 96 | 1.5% | 6535 |
| UKPN | 231 | 4.8% | 233 | 4.8% | 4833 |
| SPEN | 270 | 8.3% | 48 | 1.5% | 3270 |
| SSEN | 235 | 5.9% | 140 | 3.5% | 4018 |

This comparison indicates that UKPN and SSEN, and to a lesser degree, ENWL have offered the highest ongoing efficiency challenges, which is welcome. The remaining DNOs have targeted less ambitious efficiency challenges which we think should be improved.

As far as RPEs are concerned, UKPN, ENWL and WPD offer the lowest forecast increases, with the remaining DNOs offering higher increases. We suggest that these higher forecasts should be reduced. The real price effect assumptions should be based on sound evidence, recognising where companies are able to minimise these price increases.

We would like to see strong ambition in this area. We suggest that cumulative ongoing efficiency targets of above 5% should be used for all companies, recognising the potential for outperformance, given that the companies already benefit from real price effect adjustments.

We have assessed proposals for ongoing efficiency and real price effects together, considering the combined effect of these proposals. This results in UKPN being the strongest performer, followed by ENWL. SPEN has offered the least attractive proposals.

### 2.2 (iii) Uncertainty mechanisms

Ofgem has prescribed certain expected uncertainty mechanisms (UMs) in its sector methodology and, while we have considered company responses to these, we have focused particularly on the bespoke uncertainty mechanisms that companies have proposed.

We have evaluated UMs in the context of whether they are risks that the company is best placed to manage, whether costs may already be included in baselines, and whether each proposal offers value for money for consumers.

- **Balance of company or consumer risks** – each company is required to set out each risk and uncertainty mechanism with its materiality, frequency, trigger events and probability and to explain where the risk lies. In our evaluation we are looking for evidence justifying the proposed balance of risk between company and consumer. We are seeking to ensure that the companies are efficiently managing the risks that they are best placed to manage and that risk is only passed to consumers when it becomes an unmanageable risk for the company. We also think there should be a materiality factor so that there is a focus on the most material risks being addressed through uncertainty mechanisms.
- **Value for money –** for each risk, the company is required to describe and quantify the proposed uncertainty mechanism, setting out benefits and drawbacks (and their materiality). We have considered whether we think the risk may already mitigated by proposed baseline expenditure, and whether the uncertainty mechanism offers value for money. In this regard we have also considered the proposed volume drivers and the risk of them being set inaccurately.

We scrutinised companies' proposals for uncertainty mechanisms and our scores are shown in the table, below:

*Table 24: Uncertainty mechanism scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Totex: Uncertainty mechanisms** | 2 | 3 | 2 | 2 | 4 | 4 |

In order to assess uncertainty mechanisms, we have taken two approaches: firstly to assess the costs proposed by companies for their UMs in business plan data tables; and, secondly to consider the proposals set out by companies in their plans and supplementary materials.

The following table lists the proposed uncertainty mechanism costs proposed by each company, breaking them down into load-related capex, non-load capex, and other uncertainty costs. We have not included potential additional forecast costs relating to the Access Strategic Code Review which could add another £1.2bn according to DNO forecasts.

*Table 25: Uncertainty mechanism costs*

**ED-2 Uncertainty mechanism costs**

| £m | ENWL | NPg | WPD | UKPN | SPEN | SSEN | Total |
|---|---|---|---|---|---|---|---|
| **Load related** | 89 | 195 | 1,295 | 747 | 213 | 240 | 2,779 |
| *LRE UM % of totex* | *5%* | *7%* | *20%* | *15%* | *7%* | *6%* | |
| **NLRE** | 102 | - | 3 | 181 | 30 | 615 | 931 |
| **Other UM costs** | 33 | - | - | - | - | 193 | 226 |
| **Total UM costs** | 224 | 195 | 1,298 | 928 | 243 | 1,048 | 3,936 |
| *UM % of totex* | *13%* | *7%* | *20%* | *19%* | *7%* | *26%* | |

Overall, these uncertainty costs total just under £4bn, with the vast majority being targeted as load-related mechanisms. We note that SSEN has presented uncertainty costs that total 26% of their totex, with WPD and UKPN proposing levels of around 20%.

***Load-related uncertainty***

Turning first to load-related capex, we recognise that the capex forecast for ED2 will be uncertain due to:

- **Upward volume drivers –** primarily for extra reinforcement needed for additional demand from EVs and heat pumps, despite overall ED2 peak demand not exceeding historic levels.
- **Downward volume drivers –** primarily from the use of flexibility, and increased network utilisation from smart control. Distributed renewables and storage will also reduce demand.
- The **differing levels of existing network capacity headroom**, which may differ by location, timing and customer behaviour. For example, overall peak capacity appears unlikely to grow above historic levels by 2028.

We consider that a load-related capex uncertainty mechanism will be an important requirement for ED2 to facilitate the uptake of LCTs and enable Net Zero, and we support this approach. But we are concerned that an unduly high capex baseline may lead to windfall gains for companies if demand does not increase and they do not invest, or indeed they may invest in assets that are not needed. One issue of particular concern is that the advancing of reinforcement expenditure for ED3 will curtail any opportunity for flexibility markets or smart control systems to provide an alternative cheaper solution to Regulatory Asset Value (RAV) investment.

We note that, during ED1, a lower-than-expected low-carbon technology rollout led to lower than expected demand and lower investment by DNOs. All DNOs (except UKPN) appeared to manage their expenditure so they did not trigger this reopener and were able to retain these underspend gains.

We suggest that Ofgem may wish to consider a load-related UM that uses a baseline assessed by Ofgem for each company based on well-justified expenditure, and that this should include (only 'one touch') anticipatory expenditure, such as increasing cable capacities. To ensure that additional capacity growth may be captured, this should be accompanied by appropriately calibrated uncertainty mechanisms, together with price control deliverables and reopeners for high-value projects.

We note that work is still underway between Ofgem and DNOs to develop a suitable set of volume drivers for this purpose. As such, we have not commented on the individual volume driver proposals made by companies. The overriding imperative is that the investment needed to implement Net Zero should be delivered. However it is also essential that any uncertainty mechanism is appropriately calibrated and monitored, so as to ensure that it does not lead to windfall profits for the companies; for example, if, an investment financed by the mechanism turns out not to be required until a later period, to ensure that it is not paid for twice by the consumer.

***Other bespoke uncertainty mechanisms***

We note that NPg and WPD have not proposed additional bespoke non-load uncertainty mechanisms, and UKPN has only identified reopeners for potential rail diversions. However, the absence of uncertainty mechanisms does not necessarily give us more confidence that they are not unduly passing risks to consumers that they are best placed to manage. These companies may simply be placing risk contingencies in their baseline forecasts, and we note that all these companies have significantly increased their baseline expenditure. As such the potential costs identified for managing these risks may be excessive. We would expect Ofgem's totex assessment to focus on this issue.

We consider that SPEN, ENWL and SSEN are the weaker performers. All have identified a range of additional bespoke uncertainty mechanisms ranging from wayleave compensation claims, PCB transformer replacement, to Scottish Island cable reopeners. We agree that some of these risks – for example, wayleave compensation and PCB removal – are uncertainties but that the individual companies may be best placed to manage these risks instead of passing them to consumers. It may be appropriate for efficient expenditure to be included in baseline rather than in uncertainty mechanisms. For SSEN's major project proposals, we consider they could be categorised as reopeners and be evaluated on a case-by-case basis during the price control.

We note that the potential costs associated with these uncertainty mechanisms described in plans are either not included or do not appear to reconcile with BPDT submissions. This makes it difficult to assess the true cost of these mechanisms and the proposed balance of risk. We have provided our detailed views on these mechanisms in individual company chapters.

Overall, based on the limited time we have had to review these, we consider that the best performers in this area should demonstrate that they have included efficient costs in their baseline and justified the need for any cost risks in addition to LRE to be addressed by UMs. In this regard, we consider UKPN and WPD to be the best performers because of their lower-than-average totex increases and limited additional UMs. NPg has also limited the additional risk passed to customers but has proposed a higher baseline.

In summary, we think that WPD and UKPN have provided a more appropriate balance between baseline and risks passed to customers through UMs, although we still have concerns about the scale of corresponding baseline expenditure that is potentially included and whether this is efficient. However, we expect Ofgem to validate and assess all these proposals, taking account of potential bias to the company's benefit. Where a company's proposals are taken forward, we expect the benefits to the company of risk mitigation to feed into an overall calibration of risk/reward within the price control settlement.

## 2.3 DSO and whole system

### 2.3 (i) DSO and digitalisation strategy

Ofgem's RIIO-ED2 sector methodology decision aims to support Net Zero targets and the energy transition while keeping the cost to existing and future consumers as low as possible. The key objective is to optimise efficiencies across the entire energy system, including the full utilisation of flexibility resources that are becoming available in a more decentralised energy system, plus the use of smart technology and data.

The Challenge Group strongly supports the development of a more flexible whole energy system to deliver both cost efficiencies and enable the energy transition. Increasing visibility and flexibility across the whole energy system can reduce the cost of achieving the energy transition while maintaining energy security and resilience. Visibility of DNO network data, including to third parties, will be a critical enabler.

However, there are some key challenges to be addressed. The proposed growth in DSO activities and benefits over RIIO-ED2 represents a major step change from today, and the full benefits may not be realised. For example, effective arrangements are needed for DSO coordination across the whole energy system, i.e. with electricity transmission, with local/national electricity markets, with distributed energy resources, and with the other energy vectors of heat and transport. Commercial and regulatory incentives will need to be aligned, and market barriers addressed.

A key factor to be addressed is ensuring common measurement of DSO flexibility and smart control benefits, not just from optimising distribution network use and enhancing resilience, but also from increased competition in wider energy markets. We suggest that measures of DSO benefits could identify improvements in network utilisation and volumes of distributed energy resources traded across all energy markets.

In our review of DNO plans, we looked for proposals that demonstrate customer benefits from:

- **Network visibility –** they are enhancing their network visibility, both of capacity and utilisation and they are exposing that data to third parties.
- **Local flexibility solutions –** they are enhancing network control and management, including active network management and flexibility markets with distributed energy resources to enhance utilisation and resilience. They are reducing their network investment needs.
- **National market solutions –** they are enabling distributed energy resources to participate in national network flexibility markets, and in other balancing and energy markets.
- **DSO plan delivery –** they have a robust plan for DSO delivery and benefit realisation.
- **Digitalisation –** they have integrated digitalisation plans with implementation of DSO functions.
- **Whole system benefits –** these are demonstrated from engaging with the national electricity system via the ESO and with customer (behind the meter) resources, including in the areas of heat and transport.

We scrutinised companies' plans for DSO initiatives relating to these elements and our scores are shown in the table below:

*Table 26: DSO scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Outputs: DSO and digitalisation strategy** | 4 | 2 | 3 | 3 | 5 | 2 |

We considered that UKPN's DSO strategy seemed the strongest, providing a rationale for the choices made and providing the strongest evidence for delivery and justification of the cost benefits that were expected. UKPN sees the role of the DSO as going beyond flexibility and is the most ambitious of the DSO plans. The ENWL plan also provided evidence to support delivery and benefit realisation. The other DSO strategies appeared to be an evolution of their ED1 DSO work, providing less confidence that the step change in DSO activity and the potential benefits would be realised.

We have then compared the different companies in more detail. We have scrutinised network visibility, costs and benefits.

### *Network visibility*

A key enabler for active networks and flexibility markets is network visibility. We consider that assessing the LV network flows is very important to understand power flows and optimise network utilisation. Metering at LV substations will need to be supported both by the use of smart metering data and by advanced system modelling tools. This power flow and network utilisation data should be provided to third parties and enable market-based congestion management in LV networks.

All DNOs have reported that they have 100% visibility through network monitoring on the primary networks. However, there are differing rates of progress in providing visibility on their secondary networks.

The following table sets out the targets each company has provided for monitoring coverage of LV substations by 2028, with NPg indicating the highest target and WPD the lowest. However, as some DNOs expect to use smart meter data to support their own LV monitoring, this makes it difficult to assess how these targets will deliver network capacity and utilisation visibility to the DSO and third parties.

*Table 27: LV substation monitoring targets*

| | LV substation monitoring (%) | |
|---|---|---|
| | 2023 | 2028 |
| ENWL | 11% | 35% |
| NPg | 11% | 50% |
| WPD | 2% | 11% |
| UKPN | 13% | 22% |
| SPEN | 3% | 19% |
| SSEN | 2% | 19% |

While useful, this measure of LV meter penetration is an input measure rather than an output measure. We suggest that any targets set by Ofgem for network visibility should be focused on the amount of capacity and utilisation data that is both measured and is available for use by third parties.

***DSO costs***

The following table compares some of the key cost and resource proposals from the DSO plans for ED2. The table also compares the DSO costs per MW of 2028 peak demand for each company, and the proposed staffing increases in full-time equivalents (FTE).

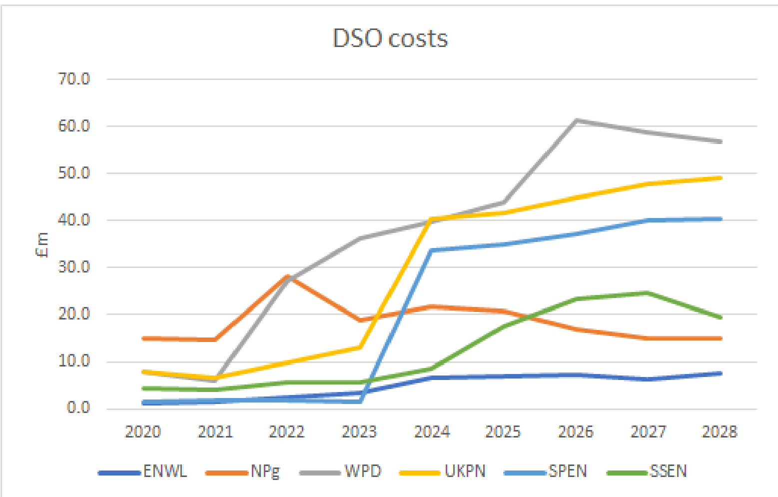
*Table 28: DSO costs and resources for ED2 by company*

| | ED2 DSO totex (£m) | 2028 peak MW | £m/ 2028 MW | DSO FTE 2021 | DSO FTE 2028 |
|---|---|---|---|---|---|
| ENWL | 35 | 4,899 | 7,149 | | 40 |
| NPg | 90 | 6,662 | 13,439 | | 48 |
| WPD | 261 | 15,079 | 17,276 | | 72 |
| UKPN | 224 | 15,138 | 14,788 | | 162 |
| SPEN | 186 | 6,871 | 27,112 | | 188 |
| SSEN | 93 | 10,223 | 9,134 | | 139 |
| Total | 889 | 58,872 | | 127 | 649 |

- **Costs –** the table shows that the proposed DSO totex over ED2 totals some £890m. We estimate from company submissions that this is an increase of around £660m from the equivalent DSO activities in ED1. For individual DNO expenditures, SPEN appears to have the highest DSO/2028 peak MW cost, with ENWL and SSEN having the lowest. However, we understand this may be due to SPEN's allocation of costs to this category differing from other DNOs. We ask Ofgem to investigate this further.
- **Staffing –** the forecast DSO headcount increases significantly between 2021 and 2028 for all companies, with SPEN forecasting a ten-fold increase. Overall, there is a five-fold increase, which may present challenges in training and recruiting the specialist staff required.

The following charts shows the profile of DSO costs forecast by each company from 2020 to 2028. All companies except NPg show significant cost increases over this period, with the most significant increase at the start of the ED2 period.

*Chart 5: DSO costs by company (data from BPDT submissions)*




Overall, this analysis suggests that most companies are making a step change in their DSO activities; this is welcome. However, there are some significant differences between the level of forecast expenditure (particularly in IT expenditure) which raises concerns about efficient delivery. The staffing levels differ and the dramatic increase in these resources may be difficult to deliver.

***DSO benefits***

The following table lists the individual company proposals for MW of flexibility benefits, including flex resources they expect to procure from their customers during ED2, and other savings they have identified. It compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table 29: DSO flexibility and benefits for ED2 by company*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| ENWL | 4,899 | 759 | 1379 | 28% | 182% | 249 |
| NPg | 6,662 | 554 | 138 | 2% | 25% | 155 |
| WPD | 15,079 | 1842 | 610 | 4% | 33% | 94 |
| UKPN | 15,138 | 1822 | 732 | 5% | 40% | 601 |
| SPEN | 6,871 | 558 | 550 | 8% | 99% | 370 |
| SSEN | 10,223 | 3222 | 5000 | 49% | 155% | 18-46 |
| Total | 58,872 | 8757 | | | | |

- **Flexibility –** the table shows the target annual flexibility MW for each company as a % of 2028 peak demand, with NPg having the lowest forecast for flexibility utilisation. SSEN forecasts a target flexibility which would be 49% of the 2028 peak, and ENWL's forecast would be 28% of the 2028 peak.
- **Benefits –** the table also shows the direct LRE savings for ED2 identified in the plans through the implementation of DSO smart control and flexibility measures. This is claimed to represent the benefits from network investment that is deferred or obviated by the DNOs over ED2. While we recognise that there are significant differences in the way these savings have been calculated, they appear to total around £1.5bn, which is about 50% of the planned load-related capex across all companies, which appears inconsistent with plans for load-related expenditure. Across all DNOs, there does not appear to be a consistent way of measuring or valuing flexibility. As such, we are concerned that this leads to non-optimal investment or flexibility decisions being made. We suggest that a common approach to defining and assessing DNO flexibility benefits should be defined.

Overall, taking account of both the proposed DSO costs and benefits, we note that the total DSO cost for ED2 is forecast to be some £890m which is a significant (£660m) increase in expenditure from ED1, with SPEN having the highest cost per MW of expenditure. We are concerned that direct and indirect benefits are not being captured and that potential DSO benefits may be overstated due to higher than necessary baseline expenditure forecasts.

One of the key benefits of investment in DSO capabilities should be to attain reductions in network reinforcement expenditure. We would suggest that Ofgem should investigate further to ensure that efficient DSO costs are allowed, with a clear linkage to DSO delivery and benefit realisation targets.

### *Additional DSO comments*

The proposed growth in DSO activities and benefits over RIIO-ED2 represents a major step change from today. Effective arrangements are needed for DSO coordination across the whole energy system, i.e. with electricity transmission with local/national electricity markets, with distributed energy resources and with the other energy vectors of heat and transport. Commercial and regulatory incentives will need to be aligned, and market barriers addressed. We strongly endorse the need to exploit the benefits of flexibility ensuing from efficient DSO and digitalisation developments, but there are a few wider concerns and risks we would also like to raise:

- **Creating new market barriers –** while we welcome the goal for DSOs to enable distributed energy resources to participate in all available energy markets, the DNO proposals for flexibility markets appear to focus primarily on their own network congestion issues. While this is a welcome start, there is a risk that creating new, potentially real-time markets for this purpose puts control infrastructure and governance in place, which inhibits access to price signals by customers wishing to participate in potentially much larger volume energy flexibility markets. New network-centric flexibility markets may have the perverse effect of chilling investment in distributed energy resources and restricting benefits from potentially more valuable demand response assets.
- **Governance arrangements –** we have concerns about the governance arrangements proposed for DSO activities, and the risk that DSO activities are developed for DNO network business self-interest. For example, while potentially attractive, the UKPN plan which proposes greater DSO separation could create new market barriers to third-party participation by adding complexity and cost. We note that ENWL is proposing a CVP for their CLASS technology that, subject to regulatory decisions, provides a fast response service to the Electricity System Operator (ESO) in competition with other fast service providers. Assuming that this service operates in a competitive market, we do not consider it should receive an additional CVP reward.
- **Benefit delivery risk –** DSO benefits will be delivered through integrated digitalisation and DSO plans. We found most of the plans, except for UKPN, gave little confidence that benefits from DSO investments could be delivered. There is a risk that the investment in DSO for ED2 may raise concerns similar to that for smart grid initiatives in ED1, i.e. that limited measurable benefit may have been delivered for the totex allowance. We suggest that measures of DSO benefits could identify improvements in network utilisation and volumes of distributed energy resources traded across all energy markets.
- **Enhanced network resilience and utilisation –** the introduction of enhanced DSO capabilities offers significant benefits that may be gained from greater use of network control to use untapped demand-side resources and dynamic ratings of networks. We found limited evidence that DNOs were seeking to deliver these benefits.
- **Whole system –** overall, except for the UKPN plan, we found limited evidence of engagement with the ESO or others to seek whole system benefits.
- **Co-ordination –** there are six different DSO strategies proposed by the DNOs and the pace and scope of planned developments appears to differ considerably. Overall, based on the information provided so far, we are concerned that the DSO initiatives may be network-centric, narrowly-focused and uncoordinated, putting the potential benefits at risk. Also, the development of six different IT systems, or seven if the ESO system is included, may result in wasteful expenditure if incompatibilities need to be addressed in future.

- **DSO incentives –** we understand that DSO incentives are likely to be designed around the delivery of: a) network operation, b) market development, and c) planning & network development activities. Performance targets may be measured in terms of network data visibility, flexibility market participation and improved planning information. However, these may be considered to be input measures and not measures of outcomes. We suggest that any performance incentives be based on measured outcomes such as customer benefits from reduced network investment costs or reduced system balancing costs.

We would suggest that these factors should be considered and addressed by Ofgem in its regulatory decisions for DSO activities in ED2.

### 2.3 (ii) Whole system strategy

As for DSO strategies, the Challenge Group strongly supports the development of a more flexible whole energy system to deliver both cost efficiencies and enable the energy transition. Increasing visibility and flexibility across the whole energy system can reduce the cost of achieving the energy transition while maintaining energy security and resilience.

To help enable benefits from a whole system approach, DNOs will need to engage beyond their own network and investment plans into the needs of their customers (including beyond the meter), into the ESO and national electricity markets, and into the heat and transport vectors. This external perspective will require a significant change in approach for most companies.

In our scrutiny of DNO plans, we are particularly seeking to understand the costs and benefits of new whole system initiatives (over and above business as usual) that companies plan to undertake in coordination with stakeholders across electricity and other sectors.

In our review of DNO plans, we looked for proposals that demonstrate customer benefits from:

- **Internal actions –** how companies are using whole system strategies to enhance the utilisation and efficiency of their own network operation and investment.
- **External actions –** how companies are using whole system strategies to enhance the utilisation and efficiency of third-party energy systems, e.g. contributing to ESO balancing cost savings or contributing to efficiencies from local area energy plans.
- **Culture change –** how companies are transforming their own organisational processes and governance to help understand and realise whole system benefits.
- **Whole system plan delivery –** whether companies have a robust plan for whole system plan delivery and benefit realisation.

We scrutinised companies' plans for whole system initiatives relating to these elements and our scores are shown in the table below:

*Table 30: Whole system strategy scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Outputs: Whole system strategy** | 2 | 2 | 2 | 4 | 4 | 2 |

We considered that the whole system strategies and plans for UKPN and SSEN appeared to be the strongest. UKPN had quantified potential whole system benefits both internally and externally, including coordination with the ESO to deliver whole system benefits, and plans to engage with Local Authorities (LAs) to develop local energy action plans appear well designed. SSEN had detailed how it was going to change its business culture and prioritise whole system issues and benefits. We considered that most other companies' strategies appeared to be a continuation of business-as-usual and the realisation of benefits appeared uncertain.

At draft plan stage, SPEN's plan did not include a whole system strategy and we welcome that this was addressed for the final plan. However, while their strategy appears comprehensive in terms of ambition with a new business operating model, implementation plans seem to be relatively high level and uncertain.

We have scrutinised and compared the main initiatives proposed by network companies in relation to their whole system strategies. These are illustrated in the table, below.

The table lists some of the key initiatives that are included in the baseline plan and some that are proposed as Customer Value Propositions (CVPs). We have commented separately on the CVPs.

*Table 31: Whole system – key initiatives proposed by each DNO*

| ENWL | NPg | WPD | UKPN | SPEN | SSEN |
|---|---|---|---|---|---|
| Ensuring whole system thinking is built into network development processes<br><br>Whole energy and heat system interactions with key stakeholders<br><br>Whole transport system interaction with key stakeholders<br><br>Whole system customer service interactions, e.g. Smart Street, energy efficiency | Remove barriers for customers to use their equipment<br><br>Whole system planning, e.g. local energy action plans<br><br>Rolling out proven innovation, e.g. voltage optimisation<br><br>Exchange knowledge about LCT product and service design | Internal whole systems training<br><br>Whole systems management team<br><br>Collaboration with Welsh assembly, NG, WWU and SPEN<br><br>Funding support for community energy groups<br><br>Regional development plans<br><br>Whole system development register | Whole electricity: incl. regional development plans, and flexibility development plans<br><br>Whole transport: incl. collaboration with LAs to coordinate rollout of charging infrastructure<br><br>Whole heat: incl. informing LA decarbonisation plans; make off gas grid homes ready for electrification of heat and transport | Ensure whole system thinking and engagement, incl. internal and external coordination, and support to LAs and communities<br><br>Implementing a whole system planning function through a new target operating model<br><br>Business transformation: implement a whole system policy and governance framework | Business change incl. change management, redefine internal processes, training, and new measures<br><br>Review > £2m load investments for whole system solutions<br><br>Data portal for LAs, community groups and others<br><br>Engage with stakeholders and support 200 community groups and 72 LAs |

Overall, we welcome the fact that all DNOs have proposed strategies and activities which should help enable whole system benefits to be realised. All have proposed to increase their level of outreach and co-ordination with external stakeholders, including across other energy vectors. Some companies, such as SSEN and SPEN, have proposed significant changes to their internal business model.

However, limited information is provided on potential performance measures and output targets and benefits arising from these activities. The various commitments generally seem to describe activities that are under DNO management control rather than delivering joint benefits. For example, it is unclear how these whole system initiatives may fully consider options for non-DNO network solutions.

While we support the development of whole system plans for RIIO-ED2, we would like to ensure that appropriate measures of performance and incentives are established. Similar to DSO, we suggest that any performance incentives be based on measured outcomes, such as customer benefits from reduced electricity network investment costs or reduced heat or transport system costs.

## 2.4 Other outputs

### 2.4 (i) Environmental Action Plan (EAP)

In reviewing the environmental commitments in the DNO Business Plans, Environmental Action Plans and associated strategies we have focused on decarbonisation of the networks. This is not to undermine the importance of other commitments to address environmental impact but given the need for this price control to be focused on the pathway to Net Zero, and the excellent work which stakeholders and CEGs have done in challenging all the companies in relation to all aspects of their EAPs, this seemed the area where it would be most valuable to look across the plans.

Looking at these aspects of the EAPs, we have assigned the DNOs the following ratings shown the table below:

*Table 32: EAP scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Outputs: EAP** | 3 | 3 | 4 | 3 | 4 | 3 |

***Business carbon footprint***

All the DNOs rightly identify that, given their role in bringing about decarbonisation of the grid, they should also be playing a leadership role in decarbonising their networks and addressing their own business carbon footprint. We found some good signs of this sort of leadership but were disappointed that others did not seem to be particularly well informed and showed a lack of ambition in relation to helping to address the emissions of their supply chain.

For most DNOs, losses (which form part of their scope 2 emissions for the purpose of the Greenhouse Gas protocol and Science Based Target) account for around 90% of their carbon footprints. DNOs note that this part of scope 2 emissions will inevitably reduce as the carbon intensity of electricity supplied through the grid diminishes, regardless of other actions taken by DNOs to tackle their BCFs. Nevertheless, in line with Ofgem baseline expectations and the clear expectation of stakeholders, all DNOs have put forward plans to address their own BCF. Some (notably SPEN and UKPN) are also committing to challenging targets to reduce indirect carbon emissions incurred in their supply chain. We would have liked to see more ambition in relation to these scope 3 emissions in some other plans and a recognition that as losses become less carbon intensive, supplier emissions will form a more significant part of BCF.

Given the importance of keeping bills as low as possible over the next price control, it is important that decarbonisation plans are efficient and cost effective. We were generally disappointed by the limited optioneering revealed in the Business Plans and the EAPs. This was generally confined to different versions of the same proposal rather than exploring the comparative impact of expenditure in different areas in achieving reductions (e.g., energy efficiency measures compared with installing solar panels). The impact of taking no action is referred to in most if not all EAPs and is included in the BPDT but could usefully be included more prominently as a counterfactual.

### *Science Based Targets*

It is part of Ofgem's baseline expectations that DNOs should adopt a Science Based Target (SBT). Most are now well advanced (5 in place, 1 committed and in process of verification) but this is a fast-moving area. DNOs show little awareness of the latest SBT criteria published in October 2021, but announced in July, which will require a 1.5°C trajectory and a near-term reduction target over a period of not more than 10 years. Although the revised criteria will not take effect until later this year, DNOs may need to review their targets within the ED2 period. We welcome express commitments from one or two DNOs to revisit their SBTs during ED2 but would have expected others to include this. In addition, although most DNOs make reference to the new UK Government target (68% reduction by 2030 and 78% by 2035, against 1990 levels), most do not explain whether they have considered this for themselves and how their proposals reconcile with it (beyond their role in facilitating decarbonisation of the grid). DNOs have a role to play in staying in touch with latest thinking and guidance on targets and SBTs so that they in turn can be leaders within the supply community.

### *Benchmarking and comparative information*

We recognise that comparisons between companies' targets may not be helpful because of the variety of factors affecting the carbon footprint of different networks and the variation in the balance between inhouse work and contracting out. Nevertheless, we think benchmarking and awareness of best practice against and from DNOs and the wider utility sector is useful and commendable. One of our key challenges to the companies in September 2021 was that ED1 performance information, targets and the impact of proposed actions and benefits should be expressed clearly in consistent units (ideally both in absolute and percentage terms) so that stakeholders can see and understand progress and the impact of actions and compare companies. We still feel that this has not been achieved in all business plans and EAPs. Quoting targets for reduction in tonnes of CO2 emitted without a sense of scale is often not very enlightening. We also note that ideally EAPs should be both clear and concise so that they are used and useful for the DNO.

### *Net Zero with offsetting*

UKPN and WPD have decided to adopt near-term (2028) Net Zero targets. We consider that there is little justification for these more ambitious targets given that reaching them relies on offsetting and that this use of Net Zero targets in not consistent with SBT guidance (the Science Based Target initiative (SBTi) places emphasis on early reduction of emissions, then abatement and use of offsets as a last resort to reach Net Zero). Whilst we recognise that DNOs can point to stakeholder support and that wider considerations (regional ambition or Group policies etc.) may be driving early Net Zero targets, we are not convinced that it is appropriate for offsetting to be funded by consumers. SPEN's ambitious target of carbon neutrality for Scope 1 and 2 by 2023 also relies on offsetting, but this has been carefully distinguished from its Net Zero target of 2035.

### *Specific decarbonisation proposals*

Given the need for long-term carbon mitigation, proposals for limited in-area measures which will create carbon sinks are welcome, particularly where proposals also deliver biodiversity benefits. We are particularly pleased that some companies are taking account of expert stakeholder views to include peat repair and seagrass as well as tree planting. We also welcome signs that DNOs are exploring whether energy efficiency delivers benefits in terms of reducing demand on the system to minimise losses as well as addressing fuel poverty.

Plans show different approaches to fleet replacement. This is explicable due to different fleet make-ups and to local factors (e.g. ultra low emission zones and local or regional carbon reduction plans). However, we would expect that DNOs would be replacing vehicles with internal combustion engines (ICE) at the end of their economic life and that this should lead to most vehicles being replaced by 2030. We note that in several plans the unit costs both of vehicles and charger installation look high. We also suggest that it is the incremental costs of EV v ICE rather than the full EV cost which should be taken into account, with increasing evidence that the whole life costs of EVs and ICEs are similar. Although a focus on electric vehicles is understandable, we would expect companies at least to consider the case for other fuels, especially drawing on the experience in other utility sectors.

Where carbon reductions are achieved through energy savings, it is not easy to see if these have been reflected in the opex budgets.

***Sulphur Hexafluoride ($SF_6$)***

All plans recognise the long-term challenge of avoiding adding to the $SF_6$ bank and the need to find a safe and cost-effective replacement, especially for low voltage equipment. But, given that alternatives are now available for some high voltage equipment, we think the case could be made for more ambition in using non-$SF_6$ equipment. Leakage performance has varied between companies in ED1 and we recognise it needs to be treated with caution, given the different make-up and age profiles of networks. We were pleased that at least one DNO is looking to make significant progress in tackling leaks but were disappointed that other DNOs gave little justification for adopting targets which are already being met or exceeded.

### 2.4 (ii) Vulnerability strategy

Even the most modest vulnerability strategies propose commitments which, if delivered, would represent a significant step up in the scale and value of support offered by DNOs to customers in vulnerable circumstances. Our company-by-company reviews highlight the stronger and weaker elements of each strategy, and comment on any vulnerability-related CVPs. Here we draw out overarching comments and concerns about the DNOs' strategies taken together, and the ratings assigned to each DNO are shown in the table below:

*Table 33: Vulnerability strategy scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Outputs: Vulnerability strategy** | 3 | 3 | 4 | 3 | 4 | 4 |

***Measurability of vulnerability and support offered***

Maintaining a comprehensive and accurate register of customers whose circumstances match the various definitions of vulnerability is crucial to DNOs being effective in this area. But we found it difficult to compare company proposals for the reach and quality of their Priority Services Registers (PSRs), and to take this fully into account in our ratings, because they were still using a number of different measures. In the short term, it is vital that Ofgem completes its collaborative work with the DNOs to agree meaningful, outcomes-based measures that allow comparisons on a like-for-like basis. If, once applied, these common metrics reveal significant differences, Ofgem will need to consider the implications of customers in different areas potentially receiving such different levels of service. For example, it appeared that, by 2028, NPg anticipates that it will have registered only half of the customers eligible to receive additional support in a power cut. By comparison, 80% of SPEN's eligible customers and 86% of eligible customers living in UKPN's regions could expect to be signed up and receiving vital additional help.

We were also concerned that, even after challenge, there was little detail given on how DNOs understand and measure the reach and effectiveness of their support during a power cut. The customer satisfaction survey alone will not be enough, given that results already appear to be high. And yet all DNOs acknowledge that there is a long way for them to go to understand and respond to the many different needs of customers in vulnerable circumstances. Several have plans to gather and hold more information on personal needs so that they can better tailor support when it is needed. But, in order to drive continuous improvement, it is also vital that they have a robust mechanism in place to measure how effective their response is in practice. In our view, recent events with Storm Arwen have highlighted the need for this.

***Real world testing of new vulnerability activities***

As well as all the DNOs proposing significant increases in relatively established areas, most are also proposing entirely new types of activity. But, as far as we can see, none has carried out the range of real-world tests and trials that are essential to demonstrate both that they can:

- Deliver activity at this scale; and,
- Realise the promised benefits in practice, especially at the levels claimed.

There is still time in the last year of ED1 for DNOs to start these trials and we think that, where relevant, Ofgem should make funding contingent on their taking place and delivering more compelling evidence of effectiveness and real-world benefits.

***Fuel poverty and the energy transition***

In our view, DNOs have not fully engaged with the issue of where the appropriate boundaries lie for the support they provide to consumers in vulnerable circumstances. Maintaining a Priority Services Register (PSR) and offering additional, tailored support in a power cut are squarely within their remit. But it is less straightforward to define their unique role in supporting customers in fuel poverty and, in particular, in helping to avoid customers being left behind in the energy transition. DNOs' rationale for their proposals largely amounts to: stakeholders support it and Ofgem has asked them to look at it. This is reasonable but not complete. We certainly did not see DNOs consistently and compellingly set out their rationale for different activities in a way that was clearly rooted in Ofgem's ED2 methodology decision statement that:

> *'We expect DNOs to support vulnerable consumers where the DNOs' competence and opportunity for consumer interaction puts them in the best-placed position to deliver that support.'*

The DNOs make proposals that will be beneficial for consumers, but Ofgem needs to consider further the overall strategic approach towards supporting consumers in fuel poverty and with the energy transition, especially given the step up of investment in these areas which will be passed through to customers. Framing DNOs' activities more clearly in this way should help to ensure efficient and effective delivery, and to ensure that consistent support is provided across the country.

***Measuring fuel poverty proposals***

We found that the different approaches taken by DNOs made it difficult to draw like for like comparisons between the reach and value for money of the fuel poverty measures proposed by the plans. But, on the face of it, there appear to be significant differences in cost for delivering similar activities. For example, the CVP element of UKPN's fuel poverty programme (which is the customer-funded part) promises to deliver c.£13.5m of benefit (gross) in ED2 by helping 100k customers for a cost of £9m. By comparison, WPD promises £60m of value helping 113k fuel poor customers for a cost of £2m. Ofgem must ensure that costs for broadly similar activities are efficient, especially as DNOs are planning to spend up to five times more in this area compared with ED1. In terms of the benefits delivered by these activities, DNOs have adopted a common Social Return on Investment (SROI) methodology to estimate their value. We have explained elsewhere our concern that, in some cases, this may overstate benefits (particularly when used to quantify CVP rewards). So we hope that, during ED2, DNOs will also quantify and report on the tangible, direct savings and benefits actually achieved by customers.

And while the common approach to metrics that Ofgem is working on with the DNOs is welcome, a mechanistic incentive scheme begs some questions that Ofgem will need to resolve. For example:

- If the commitments set out in the business plans are used as targets, how do you adjust for ambition? In other words, how do you avoid rewarding the successful delivery of less ambitious targets?
- If targets are not set using the DNOs' business plan commitments, then how do you avoid undermining the extensive stakeholder engagement that has taken place to develop them? Any targets that exceed a plan commitment will need to demonstrate that they are in consumers' interests (assuming that the original proposals were a trade-off with the cost of delivering them).

### 2.4 (iii) Reliability

The ratings assigned to each DNO are shown in the table below:

*Table 34: Reliability scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Outputs: Reliability** | 3 | 3 | 3 | 3 | 4 | 3 |

Customer Interruptions (CI) and Customer Minutes Lost (CML) are the core measures that are used to measure networks' reliability performance, and to reward or penalise them for this, under Ofgem's Interruptions Incentive Scheme (IIS). Ofgem will decide the final targets for DNOs at the time of its draft or final determinations for ED2. Because the core reliability targets currently set out in the plans are heavily influenced by this methodology, we have not tried to reflect this area in our ratings. UKPN's higher rating reflects the fact that we thought it represented the broadest response to the range of different reliability issues raised by Ofgem's ED2 methodology.

NPg and SSEN are the DNOs with the weakest reliability performance in ED1 and are now forecasting material improvements. This catching up is both essential and welcome and, as the comparisons in Table 35 show, it should mean that the total time that their customers lose to power cuts will be closer to the average of other networks.

*Table 35: Reliability 'targets' from the DNOs' plans and the change they represent compared with their performance in ED1.*

| | | ED2 | | | | % change from ED1 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | CI (incl. exceptional) | CML | CI (excl. exceptional) | CML | CI (incl. exceptional) | CML | CI (excl. exceptional) | CML |
| | ENWL | 25 | 25 | 22 | 22 | -28% | -35% | -28% | -26% |
| NPg | NPgN | n/a | n/a | 42 | 30 | n/a | n/a | -13% | -21% |
| | NPgY | n/a | n/a | 46 | 31 | n/a | n/a | -7% | -16% |
| SPEN | SPD | 37 | 21 | 37 | 21 | -17% | -32% | -15% | -27% |
| | SPMW | 24 | 17 | 24 | 17 | -26% | -45% | -22% | -37% |
| SSEN | SSES | 49 | 34 | 46 | 30 | -8% | -26% | -9% | -29% |
| | SSEH | 65 | 41 | 59 | 32 | -5% | -29% | -5% | -34% |
| UKPN | LPN | 15 | 16 | 15 | 16 | -2% | -2% | -2% | -2% |
| | SPN | 48 | 37 | 44 | 33 | -2% | -2% | -2% | -2% |
| | EPN | 48 | 39 | 43 | 33 | -3% | -3% | -3% | -3% |
| WPD | EMID | 37 | 19 | 37 | 19 | -12% | -14% | -11% | -13% |
| | WMID | 49 | 26 | 49 | 25 | -11% | -12% | -7% | -7% |
| | SWEST | 50 | 32 | 49 | 30 | -8% | -10% | -4% | -8% |
| | SWALES | 41 | 21 | 38 | 19 | -9% | -6% | -8% | -5% |
| | Average | 35 | 23 | 39 | 25 | | | | |

At the other end of the scale, two of the more reliable networks – ENWL and SPEN – are forecasting further significant reductions in both the number and duration of power cuts. As a further contrast, UKPN is forecasting that it will broadly maintain its current IIS performance. But this would leave its customers in London receiving a significantly better service than those in its other regions.

### *Diverging reliability standards*

Overall, if the targets set out by the BPs are eventually delivered in practice, then customers in different areas can expect to receive an even wider spread of reliability standards than now. In particular, customers of ENWL, SP ManWeb and UKPN's London network may experience only half the national average number of power cuts, with SSEN's Scottish customers experiencing 50% more than the average (see Table 35 below for details). When Ofgem sets the final IIS targets for DNOs, it will need to consider whether there are materially different levels of customer support for increased reliability in different regions. We think it should also consider further whether its methodology – and DNOs' response to it – is driving good value for all customers, given affordability pressures and the demand for other areas of investment in ED2. Finally, it will need to ensure that the plans strike the right balance between improved reliability driven by traditional network reinforcement, and the broader resilience that will inevitably be needed to protect customers from the worst impact of extreme weather events.

### *Worst-served customers*

Ofgem has set a more demanding definition of 'worst-served customers' (WSC) for ED2, and all DNOs have included proposals in their plans to improve reliability for either all or a significant majority of these customers. ENWL makes an explicit commitment that the improvements they plan would mean that they would have no customers by 2028 whose service would meet Ofgem's definition of 'worst served'. Similarly, SSEN makes clear that their proposals are designed to remove 75% of customers from their WSC list. But with the other DNOs we were unclear what proportion of customers would remain on their WSC lists even after the proposed improvements were delivered. Indeed, SPEN's plan acknowledges this directly by saying that, even after they have delivered their proposed projects to reduce the frequency of interruptions experienced by their WSC by 33%, these customers may still meet Ofgem's new definition of 'worst-served'. Several DNOs acknowledged that the cost of completely removing some customers from their WSC lists by reinforcing the network in traditional ways was uneconomic. But only UKPN said that they would investigate alternative ways to ‘improve the experience’ of these customers.

UKPN’s plan was also the only one to offer targets to reduce the number of short interruptions experienced by customers, and to pay compensation to customers who experience more than 25 short interruptions a year. They also propose gathering more data on frequent, very short power cuts, and the ‘Total Time not supplied’ with the aim of setting themself voluntary targets in these areas by the end of the first year of ED1.

## 2.5 Consumer Value Propositions

Under Stage 2 of the Business Plan Incentive, DNOs can set out their Consumer Value Propositions (CVPs). These are specific ways in which their plans go beyond minimum requirements and beyond the functions typically undertaken by an energy network company as business usual and will lead to benefits to customers. CVP proposals are expected to relate to one of five areas of activity: services for vulnerable consumers, services to major connections customers, activities encompassed by the EAP, DSO activities and whole system approaches. DNOs are expected to provide a monetised value of the benefit which a proposal will deliver to consumers which will help to inform the calculation of the reward, if a reward is considered appropriate. The Business Plan Guidance states that where the proposal relates to the delivery of something within the ED2 period, Ofgem expects to multiply the net consumer value by the totex efficiency incentive rate to determine the size of the reward.

**Quantification of benefits**

All the DNOs have put forward at least 2 CVPs. They have all chosen to use, at least in part, the same SROI methodology to quantify benefits from their proposals. In some cases this leads to some significant claimed benefits, which might in turn lead to substantial rewards. SROI can be an important tool in capturing wider considerations in the context of cost benefit assessment but we have concerns about using it to calculate specific monetary amounts that form the basis for a reward. At very least, any benefit calculations (including assumed benefit per customer, take-up rates and how those translate into benefits where a service is being offered) will need to be scrutinised very carefully.

**CVP or BAU?**

We recognise that the DNOs have sought to apply the guidance to identify proposals which will deliver additional value. However, our assessment is that a number of the proposals are activities which should effectively be considered business as usual. This applies particularly to support for Local Authorities (LAs) in developing local area energy plans (LAEPs) and support for customers to facilitate cost-effective connections. There are some proposals that appear to us to deliver something additional or beyond business as usual. This applies particularly to some proposals for tailored advice for vulnerable consumers in relation to the energy transition.

**Appropriate methodology and rewards**

Even in the cases above, however, we think that significant further work will be required to establish likely benefits (we have suggested field trials in one case). Moreover, we are concerned that the framework and the method for calculating reward potentially confers a very significant upfront reward for something which will deliver the benefits, on which the reward is calculated, only over a substantial period. We think that any engagement which the companies have done on their CVP proposals may not have fully presented the likely costs (including the cost of the reward) to the consumer of delivering the benefit. This may have been further complicated when costs were positioned as ‘shareholder’ funded, when the (considerably larger) CVP rewards would still be paid for by customers through their bills.

We recognise that the CVP mechanism, as part of the business plan incentive structure, has an important purpose in encouraging innovative thinking during the planning process about how to deliver value for consumers. However, the CVP rewards, which relate to relatively small elements of individual plans, should not carry rewards which are disproportionate to the real benefits delivered, or to the minimal risks that DNOs bear in delivering them. We also saw several CVPs that could simply have been funded through the baseline as bespoke outputs within the DNOs’ core strategies. Any innovation and impact benefits they ultimately might deliver could therefore be rewarded (more proportionately) through Ofgem’s new Strategy Delivery Incentive mechanisms.

### Summary of company CVPs

The following table summarises our comments and recommendation on individual company CVPs. More detail can be found in the relevant company sections. The table shows the expected plan category for the CVP together with details of the forecast funding and benefits proposed for each.

A green shading for the funding column indicates that the CVP has been included in baseline totex funding, a red shading that it has not. Our colour shading for the recommendations column indicates: partial support for the proposal (amber) or rejection (red). We are not able to offer unqualified support for an additional reward for any of the proposals.

*Table 36: Summary of comments and recommendations for CVPs across all DNOs*

| ENWL CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **ENWL1 - Smart Street** - voltage management extension to 250,000 households | Whole system/ DSO | Costs of £78m included in baseline, delivering net benefits of £456m | The benefits appear overstated as customer applications will increasingly deliver similar savings; as an initiative to reduce costs for vulnerable customers, investment in energy efficiency may be better targeted with a faster payback. |
| **ENWL2 - CLASS** - continue voltage reduction at primary substations | DSO | No costs included in baseline, delivering net benefits of £19.6m | This is a commercial activity using regulated assets which is competing against other resources. An additional reward paid by consumers would be disproportionate. |

| NPg CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **NPg1 - One-stop App** for vulnerable customers | Vulnerability | No funding in baseline. Costs of £1.9m, delivering net benefits of £3.3m | This could be a valuable activity but we were unconvinced that it went beyond BAU for a DNO. Any clawback should be around lack of usage and non-delivery of benefits, not just fewer downloads. |
| **NPg2 - Open Insights self-service analytics toolkit** to facilitate planning and LCT connections | DSO/major connections | Funding of £6.7m included in baseline, delivering net benefits of £4.7m | This should be valuable but should be considered as business as usual as part of connection and DSO services provided to customers. |
| **NPg3 - Dynamic voltage optimisation** - behind the meter benefits at 30-80 % of domestic properties: claimed | Whole system | Funding of £7.9m included in baseline, delivering net benefits of £14.5m | As for Smart Street, the benefits may be overstated as customer applications will increasingly deliver similar savings; but the investment is less – suggest further analysis is completed under innovation |

| NPg CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| £20 average bill reduction per customer | | | initiatives before consideration for a CVP or included in baseline expenditure. |
| **NPg4 - Phase 1 roll out next generation energy system** (30 micro-grid solutions to enhance resilience in remote areas | Whole system | Funding of £6.3m included in baseline, delivering net benefits of £7.6m | This should be valuable but should be considered as business as usual as part of network reliability services provided to customers or through an innovation scheme. |

| SPEN CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **SPEN1 - Vulnerable customer targeted transition support:** Assistance to reduce bills by funding demand reduction technology and increasing smart meter uptake | Vulnerability | Costs of £14.7m included in baseline, delivering net benefits of £7.3m | The technology solution could be valuable. It can be targeted; savings are material and backed by preliminary pilots. Clawbacks should extend to failure to deliver savings promised, not just failure to install. We do not support the smart meter element as this is a supplier obligation. |
| **SPEN2 - EV optioneering for LAs** to identify optimum placement of charging infrastructure to save cost and accelerate roll out | Whole system | Costs of £5.4m included in baseline, delivering net benefits of £11.3m | This should be valuable but should be considered as business as usual as part of connection and DSO services provided to customers. |
| **SPEN3 - Mobile asset assessment vehicle (MAAV)** to improve fault detection, reducing losses and improving safety | Environment/ Reliability | Costs of £10m included in baseline, delivering net benefits of £2.4m | Proposals admits that benefits are difficult to quantify. Benefits case relies heavily on societal cost of avoided carbon due to reduction in losses but little real-world evidence to support these numbers. MAAV seems expensive at £2m p.a. |
| **SPEN4 - Advanced fault level management -** technology to connect generation and avoid investment if network is close to safe fault level | DSO | Costs of £2.4m included in baseline, delivering net benefit of £34.1m | This should be valuable but should be considered as business as usual as part of connection and DSO services provided to customers. |

| SSEN CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **SSEN1 - Embedded Whole system support for LAs -** embedded support to 72 LAs | Whole system | No funding in baseline. Costs of £12.3m, delivering net benefits of £11.2m | While support should be valuable, it is not evident that SSEN has the capability to provide these services, including for non-network solutions. We consider this service should be provided as business as usual as other DNOs have proposed. |
| **SSEN2 - Support delivery of island broadband -** fibre in cables to be used to deliver broadband to 14 remote islands | Whole system | No funding in baseline. Costs of £8m, delivering net benefits of £27m | The benefits of laying fibre optic cables with the subsea power cables are clear. However, the additional costs to connect the fibre optic from the beach appear to be cross-subsidisation of island broadband by SSEN customers, which would appear to deliver limited benefits. This could be considered as a commercial service. |
| **SSEN3 - Seagrass meadow planting -** 17 hect of seagrass to improve marine biodiversity and allow carbon sequestration | Env | No funding in baseline. Costs of £2.6m, delivering net benefits of £3.4m | Interesting carbon abatement project which has been informed by stakeholders and seeks to mitigate seabed damage of undersea cables. Could bring substantial benefits in marine biodiversity, carbon storage and coastal erosion mitigation. However, there are significant risks associated with deliverability, including cost, |

| SSEN CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| | | | which would have a big impact on the benefits. We would support a reward subject to it being possible to establish a reasonably robust benefit calculation. |
| **SSEN4 - Energy efficiency accelerator** for smarter networks and flex market stimulation | DSO | No funding in business plan. Costs of £36.8m, delivering net benefits of £7.1m | While local partnerships to promote energy efficiency and flexibility market participation appear valuable, this should be part of DSO business as usual activity. |
| **SSEN5 - Personal resilience plans**: targeted support for 420000 PSR customers; 21000 battery packs to PSR1 | Vulnerability | No funding in baseline. Costs of £7.3m, delivering net benefits of £3.9m | Personalised plans would be useful but it is unclear how tailored the advice would be as most of the cost is for the battery packs. Limited field trials suggest proactive delivery of packs is valued and funding can be targeted. But is this materially more than what others are doing as BAU? |

| UKPN CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **UKPN1 - Fuel poverty support** for vulnerable customers: in depth tailored interventions with partners | Vulnerability | Not included in baseline. Costs of £9m, delivering net benefits of £5.1m | This type of activity is now part of all DNOs' plans so is it beyond BAU? UKPN's pitch seems to be that the scale of activity is novel (this is half their fuel poverty programme). We are concerned that some take-up (and so benefit) assumptions are too high; and have a question over whether costs are efficient vs other DNOs for similar activity. |
| **UKPN2 - Public charging:** enabling 2400 extra public charging points | Whole system | Not included in baseline. Costs of £7.3m, delivering net benefits of £9.3m | This should be valuable but should be considered as business as usual as part of connection and DSO services provided to customers. |
| **UKPN3 - Off-gas grid customers** - delivery of capacity to facilitate transition to electric heating | Whole system | Not included in baseline. Costs of £75m, delivering net benefits of £89m | This CVP assumes that an electric solution is appropriate before heat policy decisions have been made and may not consider non-network solutions. |

| WPD CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **WPD1 - Net Zero by 2028** and stretching SBT of 1.5°C | Environment | Costs of £89.1m included in baseline, delivering net benefits of £14m | 1.5°C target is new norm for SBT. We do not think early Net Zero is useful. It relies on offsetting and may cause confusion. |
| **WPD2 - Proactively partner with every LA to develop LAEPs** (4 LA engagement engineers; surgeries; assistance for less advanced LAs) | Whole system | Costs of £2m included in baseline, delivering net benefits of £28m | We consider this service should be provided as business as usual as other DNOs have proposed. It is not evident that WPD has the capability to provide these independent services, including for non-network solutions. |
| **WPD3 - Establish Community Energy Engineers** - 4 engineers to support community energy groups and roll out of innovation; empower communities to use data | Whole system/ Environment | Costs of £1.3m included in baseline, delivering net benefits of £3.1m | Community Energy Engineers appear a good idea and have strong stakeholder support. However, we are not convinced that this goes beyond business as usual (other DNOs have similar proposals). Nor is it evident that WPD has the capability to provide these independent services, including for non-network solutions. |

| WPD CVP Description | Category | Funding & benefits | Comments and recommendation |
|---|---|---|---|
| **WPD4 - Solar PV in schools in deprived areas** to promote decarbonised energy/ local energy schemes | Vulnerability/ Whole system/ Environment | Costs of £2.7m not included in baseline, delivering net benefits of £23m (10 year basis) | A relatively small-scale project (£540k p.a.). The proposal says that it will be funded by shareholders. Significant proportion of benefits comes from SROI – is this the best way to help consumers in areas of economic deprivation? |
| **WPD5 - Bespoke smart energy plans** for 600,000 PSR customers (60% of PSR) to assist participation in smart services | Vulnerability | Costs of £5.0m included in baseline, delivering net benefits of £7.1m (10 year basis) | The assumptions are now more reasonable (and £12m less following our July challenge). Tailored advice to drive behaviour change could be valuable. Funding should be contingent on field trials showing that take-up and benefits assumptions are realistic in practice. |
| **WPD6 - £1m Annual Community matters fund** plus volunteering opportunities | Vulnerability | Costs of £5.8m not included in baseline, delivering net benefits of £16.7m | Valuable activities if genuinely altruistic and self-funded. But there is a fundamental problem with wrapping up this sort of 'socially responsible business' claim in an incentive scheme that delivers significant rewards funded by customers. |

## 2.6 Finance

Our scrutiny of the DNOs' Business Plans covered all the main issues relating to financeability and their implications for consumers; we have evaluated the financeability of each company against adherence to Ofgem's requirements as set out in its March 2021 Sector Specific Methodology Decision (SSMD)[7] and April 2021 Business Plan Guidance for RIIO-ED2.

We have analysed the companies' proposals in relation to both their Notional and their Actual Companies and have based our assessment, and the rating we have accorded the BP, on:

- Whether, in our view, the company's BP is financeable on both a Notional and an Actual basis using Ofgem's Working Assumptions (W/As);
- Whether all the measures to aid financeability set out in Clause 4.6 of the SSMD have been fully and exhaustively explored with a view to achieving the financing of the plan at least cost to the consumer (noting that these measures do not include an increase in cost of capital allowances); and,
- Whether the plan contains a clear and unambiguous assurance from the Board that it is financeable on both a Notional and an Actual basis and, where this is not the case, the acceptability, or otherwise, of measures proposed to achieve financeability (which, in all cases, include an increase in the cost of capital).

We have also noted the extent to which the company has engaged with our commentary on their draft plan and amended their approach accordingly and are critical when that commentary has been ignored.

### A 'good' Business Plan from a financing point of view

It follows from the above that we regard a 'good' final BP as one which:

- Presents analysis of its financeability, which is not only fully compliant with the requirements of the SSMD, but also clear and unambiguous both in its assumptions and the presentation of results. In particular we have considered it important that the plan draws a clear distinction between the company's own proposed assumptions and those in the SSMD (which provide for a cost of equity allowance of 4.4% plus 25 basis

[7] This document is available here.

points of outperformance wedge (OW) and which we therefore consider give rise to a requirement to carry out analysis, for the purposes of this submission, with an effective cost of equity allowance of 4.65%);

- Demonstrates that all of the measures to aid financeability set out in the SSMD (including dividend restraint and the subscription of new equity – which we note are the first two in the list set out in Clause 4.6 and which have been ignored as options by several DNOs) have been comprehensively explored. We do not consider that the fact that the plan being financeable based on a cost of equity allowance of 4.65% removes the requirement to explore measures which could enable the cost of equity allowance to be set at a lower level than that, to the benefit of their consumers;
- Is in our view financeable with a cost of equity allowance of no more than 4.65% and a cost of debt allowance in line with the W/A in the SSMD and contains a clear statement to that effect endorsed, as is required, by the Board. We are critical of, and have rated accordingly, plans which are clearly financeable on the basis of Ofgem's W/As but have either failed to provide a clear positive statement to that effect and/or have proposed assumptions (principally, though not exclusively, in relation to the cost of equity allowance), which we regard as unnecessary and hence not in the interests of consumers: the higher the alternative proposed, the less favourably we have regarded it.

None of the plans has been rated the highest score of 5, because even the highest rated in terms of a clear analysis and presentation together with financeability at 4.65% (UKPN) has proposed a cost of equity allowance of 5.5% 'as a minimum' despite clear evidence, and a board statement to that effect, of financeability at 4.65% and demonstrates little detailed analysis of measures which could support a cost of equity allowance of below 4.65%.

Equally, none has been rated the lowest score of 1, because although the considerable shortcomings of ENWL's BP have resulted in a rating of 2, they have made a serious attempt (even if driven by necessity) to explore all of the SSMD mitigating actions. They do not propose an alternative cost of equity allowance and their comment that 4.79% is the lowest cost of equity allowance needed for their plan to achieve the target rating, although not in our view necessary (see below), is the lowest mentioned by any of the DNOs.

The ratings for each company are shown in the table below:

*Table 37: Finance scores*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| **Finance** | 2 | 3 | 3 | 3 | 4 | 2 |

The table overleaf sets out key information relating to the six plans for comparative purposes.

*Table 38: Financeability of BPs – Key data*

| | ENWL | NPg | SPEN | SSEN | UKPN | WPD |
|---|---|---|---|---|---|---|
| Is the plan financeable on a Notional basis? If so, at what rating?[8] | Borderline investment grade | Yes, probably Baa1/BBB+ and certainly in our view Baa3/BBB | Yes, Baa1/BBB+ | Likely to be, in our view at Baa1/BBB+ | Very readily at Baa1/BBB+ | Yes, at least Baa1/BBB+ |
| Is the plan financeable on an Actual basis? If so, at what rating?[2] | Probably, at Baa2/Baa3 or BBB+/BBB | Yes, A3/A- | Yes A3/A- | Yes, Baa1/BBB+ | Very readily at Baa1/BBB+ | Probably but results based on Ofgem's W/As incomplete. |
| What cost of equity is requested? | None requested but say would need 4.79% to achieve BBB+ in Notional Co. | 'Above 5.8%' | 6.21% | 5.9% | 5.5% as a minimum | 4.96% |
| Clear Board statement of financeability? | Clear statement not financeable on basis of Ofgem's W/As. | Clear statement not financeable on basis of Ofgem's W/As. | Unclear – explicit statement of financeability contradicted elsewhere in plan. | Qualified statement – 'technically financeable'. | Yes, clear positive statement. | Clear statement not financeable on basis of Ofgem's W/As. |
| What cost of debt is proposed?<br><br>Proportion of index-linked debt (ILD) in Actual Co. (Ofgem W/A of 25% in Notional Co.) | 2.09% used in Notional and Actual Cos. but say this results in £90-95m underfunding across ED2. Actual ILD is 60% at start of ED2. | Accept W/A of 2.09% but say keeping additional costs, including possible small co. premium, under review. No ILD in Actual Co. | Accept W/A of 2.09% but say need small co. premium in additional costs.<br>No ILD in Actual Co. | Accept W/A of 2.09% but say need additional costs of 38-48 bps plus small co. premium. 10% ILD in Actual Co. | Accept W/A of 2.09% but say need additional costs of 38-48 bps plus infrequent issuer premium. Say 10% ILD correct for sector. | Accept W/A of 2.09% but propose additional costs of 38bps excluding any small co. premium. |
| Exploration of measures proposed to aid financeability? | Good exploration of mitigating measures including gearing and dividend restraint. | Limited. Main focus is depreciation period but analysis of lower gearing.<br>Little on dividend restraint. | Very limited and nothing on dividend restraint. | Some focus on alternative depreciation period (may wish to reconsider at FD) and cap. rates but little on dividend restraint. | Limited and rejects changes to depreciation period and cap. rate as 'not valid levers'. No attempt to determine financeability at below 4.65% CofE. | Some evidence of focus on depreciation period and cap. rate but little on gearing. No comment on dividend restraint but modelling provides for significant new equity. |

[8] Note that this is our assessment based on the results provided but not always reflective of the company's views. It does not fully reflect the impact of all potential mitigating measures.

We set out below commentary on the following:

(i) The cost of equity allowance and the outperformance wedge
(ii) The cost of debt allowance and the question of index-linked debt
(iii) The impact of mitigating measures
(iv) Overall commentary on the financeability of the BPs

**2.6 (i) The cost of equity allowance and the outperformance wedge**

The issue which provokes by far the greatest comment in the financing section of the BPs is (perhaps not surprisingly) the cost of equity allowance. All companies deal with the subject at great length and, in some cases, what we regard as an unhelpful degree of stridency. The DNOs have jointly commissioned Oxera to provide a report on the appropriate cost of equity and several have commissioned further work from entities such as NERA and Frontier Economics. We do not think it appropriate to engage here with the detailed arguments presented in relation to the components of the Capital Asset Pricing Model (CAPM) calculation. Such an analysis would be a very lengthy exercise and we do not think helpful at this stage. We comment only that the most recent independent report commissioned by the DNOs is a report commissioned by WPD from Frontier Economics and that this report post-dates submission of the draft business plans. In their draft plan, WPD made a strong case that, to achieve financeability, they required a cost of equity allowance of 5.8%. In the light of the report from Frontier Economics, they reduced that requirement to 4.96% (which we regard as still too high but nevertheless a clear indication that independent alternative views to those in the reports prepared earlier in 2021 are possible and that the trend may be regarded as downward). Although we do not propose to engage with the detail of the CAPM calculation, we offer some comments on the subject of the cost of equity allowance and the approach to it of the various DNOs.

The CAPM calculation is obviously subject to a degree of estimation and hence uncertainty. We have been clear throughout that we are supportive of the approach taken by Ofgem and, importantly, the conclusions, set out in the SSMD. We have not changed our stance. Because some of the component parts of the CAPM calculation are not observable, it is clearly open to the DNOs and their advisers to hold different opinions (although we think that repeated references to the ‘errors’ in Ofgem’s CAPM calculation are unhelpful and unnecessary).

***Appropriateness of cost of equity allowance***

We agree with the comments made by all DNOs on the need to ensure that the cost of equity allowance is set at a level, which does not jeopardise the availability of finance for the substantial investment that is required to meet the challenges of increasingly damaging weather events and the Government’s Net Zero target. We also accept that ED2 will involve levels of totex which are very substantially greater than in ED1, potentially further impacted by the results of the Access and Forward Looking Charges Significant Code Review and the fact that construction cost inflation has, at least for the short term and potentially longer, been pushed up very significantly. We further accept that, even though the inflation risk will be largely or wholly covered by indexation, the funding requirement is likely to be considerable. We do not, however, agree that serious doubt is, in fact, cast on the availability of the necessary equity finance by Ofgem’s proposed cost of equity allowance: we note, inter alia that it is not many months since one of the DNOs (WPD) changed hands at a premium to RAV which, whatever the detailed arguments about the reasons for that premium, cannot be characterised as other than very substantial indeed. We are clear that that acquisition would have been made in the full knowledge that substantial debt and equity funding would be needed in the DNO sector during ED2.

***Sector risk profile***

The cost of equity allowance obviously needs to reflect the risk profile of the sector: we do not accept arguments that the proposed regulatory settlement for the DNO sector is riskier than that for gas and electricity transmission, gas distribution or water. There are differences between the sectors with the risk profile greater in some respect for some and less in others: overall we think it difficult to sustain an argument that one is riskier than any of the others (and, if one's view tended in either direction, it would not be towards electricity distribution being the riskier). We also think it very difficult to sustain an argument that the risk of ED2 is higher than for ED1: since the companies are the same, this is a clearly principally a function of the regulatory settlement, on which we comment below.

***In relation to UMs***

Almost all the DNOs argue that the fact that so much of the proposed totex will be the subject of uncertainty mechanisms increases the risks they face (and hence the cost of equity allowance which they should be accorded). It will be important that Ofgem puts in place effective arrangements to handle requests for UM approvals on a timely and efficient basis. However, provided such arrangements are in place, we consider that the provision for companies to determine the cost of much of the proposed totex at the time that it is required rather than ex ante considerably lowers the risk profile of the settlement rather than the reverse. The fact that the proportion of expenditure to which this applies is substantial only, in our view, serves to support arguments for a lower cost of equity allowance.

***Outperformance wedge***

All the companies reject the concept of the outperformance wedge (OW) and have, as a result, carried out their analysis on the basis of a 4.65% cost of equity allowance. We persist (and despite the view expressed by the CMA) in regarding historic outperformance across a wide range of regulated utilities both in the UK and elsewhere as very well evidenced. For this reason we have been supportive of the OW. There are, of course, other mechanisms for dealing with outperformance and we hope that, whatever action Ofgem decides to take in relation to the OW, it will ensure that robust arrangements are in place to address the asymmetry of information which is an inevitable part of any regulatory settlement of this type.

### 2.6 (ii) The cost of debt allowance and the question of index-linked debt

All the companies other than ENWL broadly accept the basis of calculation of the cost of debt allowance. A number raise points in connection with the additional costs which we do not think are well supported by evidence. It is important to note that, because of the effect of gearing, quite small additions to the cost of debt can have a substantial impact on the overall cost of capital.

***Small company premia***

Almost all the DNOs have asked for a 'small company premium' or, in one case an 'infrequent issuer premium' on their cost of debt allowance. We accept that there is precedent, in the Gas Distribution and Transmission (GD&T) settlement, for small premia on the allowance for new debt for the smallest gas distribution companies. We do not regard a small company premium as appropriate for any of the DNOs. It is true that some of the individual licensees are quite small but all the DNOs other than ENWL have the option (and avail themselves of that option) to manage their debt on a consolidated basis. We do not regard a small company premium as appropriate for any of the DNOs and urge Ofgem not to have regard to any precedent which it may consider has been set in the GD&T settlement.

ENWL clearly faces issues with regard to their access to the debt markets and, in particular, the cost of some of the historic debt which they have incurred. We deal with these problems largely in the section on company specific analysis but comment: (a) that their most serious problems relate to historic debt which is due to run off during ED2; and, (b) importantly, although ENWL is smaller than the other DNOs, they are not, in fact, particularly small in the context of some of the gas distribution companies and several of the water only companies. They make a forceful case for special consideration, but we do not accept that it would be warranted.

***Index-linked debt***

A number of the companies argue that the proportion of index-linked debt for which the Ofgem W/As provide does not reflect the average across the sector. We accept that the actual figure for the sector is below the 25% in the SSMD (though probably not as low as the 10% which many of them assert) and that this flatters the results for Notional Companies. We do not think 25% is an unreasonable figure on which to base modelling for the Notional Company (the companies can obviously use their intended proportion when modelling the Actual Company): it is significantly lower than the actual figure across GD & T and also below Ofwat's assumption of 33% for the water sector. One of the DNOs (ENWL) has very much more than Ofgem's 25% assumption. Most of the DNOs do have less than 25% (and at least one has none), and it is also open to them, if they wish to match Ofgem's assumption in the Actual Company, to contract debt on that basis going forward. The market for Consumer Prices Index (CPI) ILD is still developing but we consider the issuance allowance has been set at a level which recognises that. ENWL has particular problems because of the CPI/ Retail Prices Index (RPI) mismatch on a high proportion of its ILD. We do not believe that problems stemming from one DNO's debt financing and risk management strategy should influence Ofgem's decision in relation to the sector as a whole (nor that ENWL should be accorded special consideration in relation to decisions which they have taken).

**2.6 (iii) The impact of mitigating measures**

With the partial exception of ENWL, we do not consider that the DNOs have given adequate consideration to the levers for improving financeability set out in Clause 4.6 of the SSMD: they all (and including those which say that they are financeable on the basis of Ofgem's W/As) focus on arguing for a higher cost of equity allowance rather than fully exploring other mechanisms.

***Depreciation period***

One company (NPg) makes a forceful case for a much shorter depreciation period on the basis of intergenerational fairness. A number of the DNOs refer to intergenerational fairness and use it as a basis for not giving detailed consideration to small changes in the depreciation period which might improve financeability. We point out that 'intergenerational fairness', although widely used as a reason for not loading costs incurred today onto future generations is a double-edged sword: there is a good argument for not loading the costs of the transition to Net Zero (which account for much of the expenditure planned for ED2) onto consumers whose economy is still largely carbon based (and for which, in the current market, they are paying very heavily). Across the DNOs as a whole, changes to the depreciation period and to capitalisation rates have, in our view, been very much underexplored. In some cases, the company seeks to make a virtue of using the 'Ofgem proposed rate'.

***Gearing level***

Similarly, several companies have said that they are content with the Ofgem proposed gearing rate of 60%. We take the view that 60% is a good starting point for the Notional Company but there is clear provision in the SSMD for companies to vary that rate for the Notional Company (as well, obviously, as for the Actual Company). With the exception of ENWL, we do not consider that the DNOs have given sufficient focus to the impact on financeability at least cost to the consumer of alternative gearing rates.

***Dividend restraints / new equity***

We do not consider that any of the companies have sufficiently explored the impact on the cost to consumers of dividend restraint and/or new equity. ENWL's BP provides for no dividends at all to be paid during ED2 but, despite problems with financeability, it does not make any concrete proposals in relation to new equity (although it does refer to the potential to consider this at a later stage). WPD, which describe their plan as non-financeable on the basis of Ofgem's W/As, do provide for the subscription of substantial new equity in their modelling, but project the payment of more than £1bn of dividends over the course of the price control period. Other DNOs, such as SSEN and UKPN, make general comments about the need for proper consideration of distributions and restraint where appropriate, but provide no detailed analysis of what could be achieved by dividend restraint and/or new equity. NPg refer to their shareholder having 'a track record of reinvesting heavily in our business' but, despite the fact that they say their BP is not financeable, do not show any analysis of the impact of such 'reinvestment' (or, indeed, of dividend restraint). SPEN similarly appears not to have carried out any detailed analysis of the impact of dividend restraint or new equity.

**2.6 (iv) Overall commentary on the financeability of the BPs**

It is our view that all of the BPs (probably including ENWL's) are financeable on the basis of Ofgem's W/As. UKPN makes a clear statement to that effect but propose that the cost of equity allowance should be set at 5.5%. SSEN's board statement is to the effect that their plan is 'technically financeable' but they present a number of arguments for an increase in the cost of equity allowance to '5.9-6.4%'. SPEN's plan contains an unambiguous statement of financeability on the basis of Ofgem's W/As, but also a number of statements which contradict this, leaving the position unacceptably uncertain. They propose a cost of equity allowance of 6.21%. NPg, WPD and ENWL all make clear statements that they are not financeable on the basis of Ofgem's W/As with requests for cost of equity allowances between 4.79% (ENWL) and 5.8% (NPg) with WPD's request reduced from that requested in their draft plan and now standing at 4.96% (these details are set out in Table 38 above).

***Target credit ratings***

Some of the companies argue that Ofgem's W/As do not support their target credit rating. Most target BBB+/Baa1, which we regard as at the upper end of the acceptable range. NPg says that their target rating is A-/A3, which we regard as unnecessarily high and not in the best interests of consumers (although they do say that they have assessed themself 'against a BBB+/Baa1 rating for the purposes of the BP'). We have commented in the context of all the companies individually that we are not opposed to a BBB+/Baa1 target in the base case. However, we regard it as at the upper end of the acceptable range and also that a failure to achieve that rating, particularly in downside scenarios does not mean that a company is unfinanceable: BBB-/Baa3 are investment grade credit ratings.

We have commented on the position of ENWL in the company analysis section. They are clearly in a more difficult position than the other DNOs, but their position is significantly impacted by expensive historic debt which is due to run off in the course of ED2. We are not persuaded that, on the basis of the extensive of exploration of financeability levers which they propose, probably accompanied by the subscription of some new equity, they cannot be deemed financeable. We note that ENWL are a high performing company and can reasonably hope that their position will be eased by some outperformance.

***Clear statements of financeability***

In allocating ratings to the companies, we have obviously given credit for clear statements of financeability (of which there is only one). We have been critical of (and marked down accordingly) the very muddled presentation of some of the plans, which makes it difficult to determine the basis on which their analysis has been carried out. References to ‘our plan’ which do not make clear whether the reference is to the plan on the basis of Ofgem’s W/As or the companies own assumptions are particularly unhelpful. We take the view that, the higher the proposed cost of equity, the greater the impact on consumers. For that reason, we give greater credit to companies which propose a cost of equity that is nearer to Ofgem’s W/A and mark down those which propose a very high cost of equity while clearly demonstrating (and in some cases admitting) that they are financeable.

***4.65% cost of equity assumption***

There are still some months before Ofgem has to make its final determination and market conditions could change. However, although none of the plans explores financeability on the basis of a cost of equity allowance below 4.65%, we take the view that, as of today, that may very well be possible for the sector as a whole. It is important that, in the light of the uncertainties surrounding the path to Net Zero and against the background that, whatever the exact level of totex required, it will represent a very substantial increase on expenditure in ED1, the cost of capital for ED2 is not set too low. It is also important, in the light of pressures on financial pressure on consumers generally and the recent sharp rise in the cost of energy, that the cost to consumers which feeds through from the cost of capital allowances is not too high. We consider it very important, against the multiple arguments put forward by the companies for a higher cost of equity than that currently proposed, that Ofgem keeps under close consideration that a lower cost may also be possible and should be fully explored. If Ofgem elects to base its final determination on a cost of equity without an accompanying OW we see no reason for adherence to the 4.65% which was put forward as a working assumption.

# 3. Company report – ENWL

As a summary, we have assigned ENWL's Business Plan the following ratings:

*Table 39: ENWL BP scores*[9]

| | |
|---|---|
| Track record from RIIO-ED1 | 4 |
| Scenarios and forecasts | 3 |
| Totex: LRE, incl. anticipatory investment | 4 |
| Totex: NLRE, incl. asset health | 3 |
| Totex: Network operating costs | 4 |
| Totex: Non-operational costs | 1 |
| Totex: Ongoing efficiency and RPE | 3 |
| Totex: Uncertainty mechanisms | 2 |
| Outputs: DSO and digitalisation strategy | 4 |
| Outputs: Whole system strategy | 2 |
| Outputs: EAP | 3 |
| Outputs: Vulnerability strategy | 3 |
| Outputs: Reliability | 3 |
| Finance | 2 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of ENWL's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 94% from ED1 levels and we are concerned that this may not include benefits from network capacity optimisation.
- **DSO and whole system –** ENWL are targeting annual flexibility actions of 1379MW, delivering benefits of £249m over ED2. We are concerned that these benefits may not be realised and that they are not reflected in load-related capex forecasts.
- **Costs –** Baseline totex has reduced by £300m since the draft plan but is still forecast to increase by 30% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that underlying cost increases for the same asset base are unjustified.
- **Risks and uncertainty –** ENWL have proposed a range of bespoke uncertainty mechanisms which could add £224m or 13% of totex. We are concerned that some of these costs may already be included in baseline expenditure.

  **Finance –** ENWL are clearly in a more difficult position with regard to financeability than the other DNOs, resulting principally (though not entirely) from expensive embedded debt/derivatives. They have done a good deal of analysis of Ofgem's proposed 'levers' for improving financeability but we consider there is room for further examination of the potential and would like to know what the impact of that further analysis would be on the financeability of ENWL's plan.

[9] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

## 3.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

Key performance measures are shown in the tables below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 40: ENWL ED1 performance summary*

| ED1 performance (2021 RRP) | ENWL |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 1.8% |
| Customer service (BMCS) | 0.3% |
| Time to connect (TTC) | 0.2% |
| **Output incentives total** | 2.3% |
| | |
| **Totex efficiency incentives** | 1.9% |
| **Operational RoRE** | 10.5% |

| ED1 - Totex (2021 PCFM) | |
|---|---|
| **£m (2012/13 prices)** | **ENWL** |
| Totex allowance | 1860 |
| Totex actual/forecast | 1767 |
| % totex (under)/overspend | (5%) |
| % LRE (under)/over spend | (31%) |
| % Totex (excl. LRE) (under)/overspend | (3%) |

Overall, we note that ENWL appear to underspend their totex allowance by 5%. This is mainly due to an underspend of 31% in load-related capex, largely attributable to lower-than-expected LCT growth. Totex outturn underspend would appear to be about 3% excluding load-related capex.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) performance is the highest of all DNOs but the customer service incentive (BMCS) is amongst the lowest.

## 3.2 Costs, scenarios and forecasts

### 3.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios that ENWL presents and that these scenarios appear to be consistent with Net Zero targets. We note that the company have used a Central Outlook scenario which they have identified as the highest certainty scenario that does not foreclose network future-proofing and informs the RIIO-ED2 baseline (ex-ante) allowance. This Central Outlook has not changed materially since the draft Business Plan in July.

By the end of ED2, ENWL forecast they will connect:

- 638k EVs and 79k heat pumps under their Central Outlook scenario; and,
- 699k EVs and 638k heat pumps under their High scenario.

These scenarios are presented below as ‘Best View’ and ‘Upper View’.

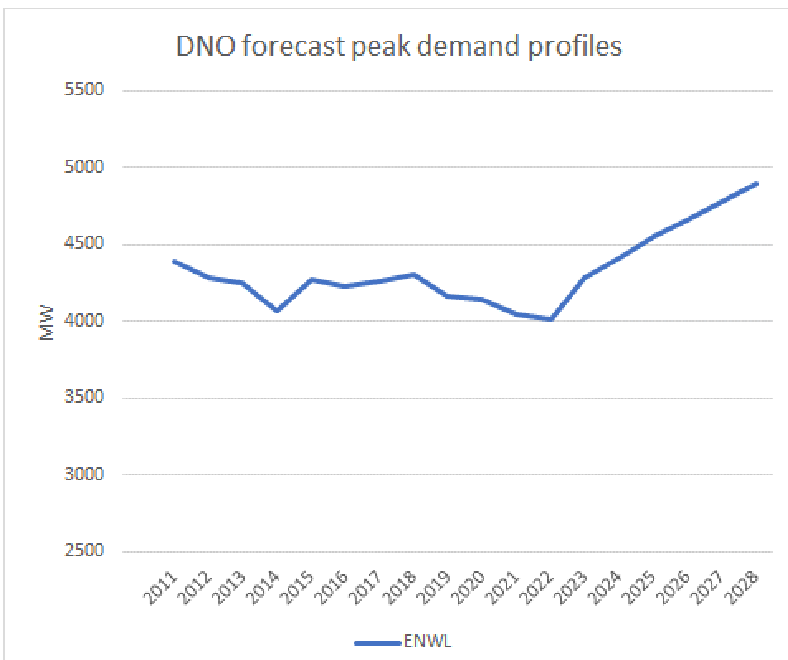
*Table 41: ENWL low-carbon technology scenarios*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| ENWL | 638 | 26% | 79 | 3% | 699 | 28% | 638 | 26% |

ENWL have around 8% of the networks' total customer base. The forecast number of EVs in the Central Outlook scenario across this customer base in 2028 is broadly in line with the ESO 2021 FES Consumer Transformation or Leading The Way scenarios, which forecast around 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers. However, the number of heat pumps increases by 3% which is lower than the 8% equivalent growth in the FES scenario. We note that ENWL consider that this reflects the relatively high level of gas heating and fuel poor customers in their region.

The ENWL submission of demand profiles in the BPDTs (shown below) shows an increase of around 18% between 2020 and 2028, which is above the equivalent peak demand increase of 11% forecast in the ESO 2021 'Consumer Transformation' scenario. While we understand that Distribution Future Electricity Scenarios (DFES) and ESO FES forecasts are prepared on a different basis, we still consider they provide a useful comparison of overall demand growth. As such, we are concerned that the apparently higher ENWL demand growth rate after 2021 is not fully justified.

*Chart 6: ENWL forecast peak demand profile*




Overall, we consider that ENWL has undertaken effective scenario planning. However, we are concerned that higher than expected peak demand forecasts, and lower than expected heat pump forecasts, have not been fully justified.

### 3.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered; and,
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages.

The ENWL ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £1,701m and is a 30% increase on the annual average expenditure rate during ED1. We welcome that the forecast has reduced from the £2,014m figure submitted in the ENWL draft plan. The following table compares the ENWL cost submissions between ED1 actuals/forecasts and ED2 forecasts. It also compares the draft and final plans[10].

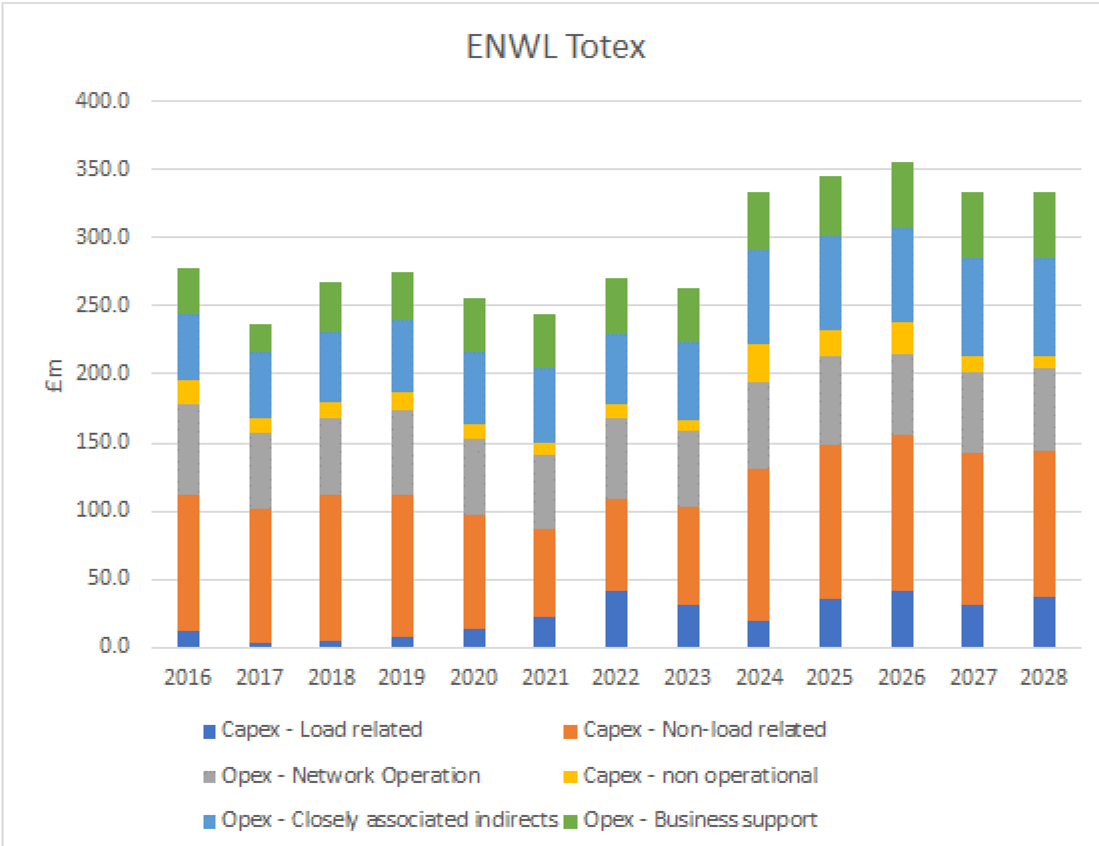
*Table 42: ENWL overall totex comparison*

| ENWL | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| Overall Totex | ED1 | ED2 | ED1 | ED2 | ED1-ED2 | ED1 | ED2 | ED1 | ED2 | ED1-ED2 |
| Capex - Load related | 135.9 | 164.4 | 17.0 | 32.9 | 94% | 119.5 | 210.9 | 14.9 | 42.2 | 182% |
| Capex - Non-load related | 697.5 | 558.1 | 87.2 | 111.6 | 28% | 713.4 | 806.5 | 89.2 | 161.3 | 81% |
| Opex - Network Operation | 461.2 | 304.4 | 57.7 | 60.9 | 6% | 461.2 | 328.1 | 57.7 | 65.6 | 14% |
| Capex - non operational | 92.6 | 92.5 | 11.6 | 18.5 | 60% | 92.5 | 87.2 | 11.6 | 17.4 | 51% |
| Opex - Closely associated indirects | 416.5 | 348.7 | 52.1 | 69.7 | 34% | 399.8 | 351.1 | 50.0 | 70.2 | 40% |
| Opex - Business support | 286.2 | 232.9 | 35.8 | 46.6 | 30% | 280.3 | 230.9 | 35.0 | 46.2 | 32% |
| **BPDT Totex** | 2090.0 | 1700.9 | 261.2 | 340.2 | 30% | 2066.7 | 2014.8 | 258.3 | 403.0 | 56% |
| **Baseline totex after OE/RPE adjustments** | | | 261.2 | 350.2 | 34% | | | | | |
| **Baseline totex with UMs (excl. Access SCR)** | | | 261.2 | 396.2 | 52% | | | | | |

A profile of the totex and main expenditure categories is shown in the next chart, showing a significant increase at the start of ED2, especially in non-load capex.

[10] Note: These totex figures exclude 'other costs outside the price control' The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.

*Chart 7: ENWL overall totex profile*




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for most ongoing expenditure, and we have scrutinised reasons for increases from these levels. Our assessments for these individual cost categories are set out below, seeking to understand the justifications for these potential increases.

### *ii.a. Totex: LRE*

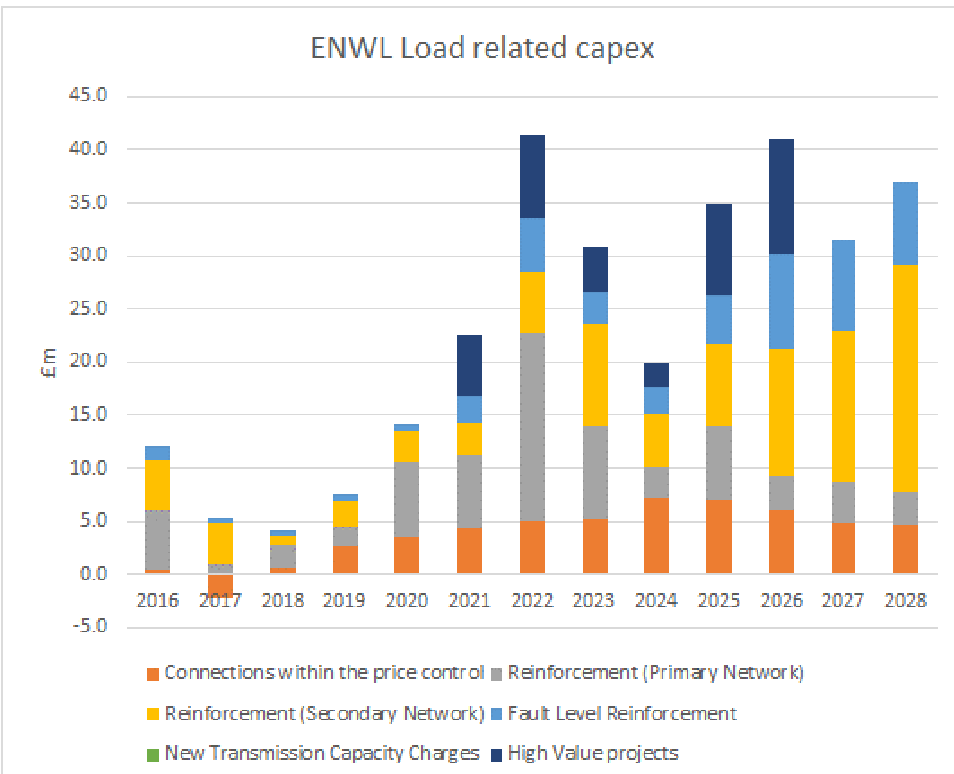
The ENWL bid for baseline LRE is £164m, which represents a 94% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual categories, with reinforcement relating to secondary networks, fault level reinforcement and connections all showing significant increases.

*Table 43: ENWL load-related capex comparison*

| Capex - Load related | Totals ED1 | Totals ED2 | Averages ED1 | Averages ED2 | % change ED1-ED2 |
|---|---|---|---|---|---|
| Connections within the price control | 19.4 | 30.0 | 2.4 | 6.0 | 147% |
| Reinforcement (Primary Network) | 51.3 | 19.6 | 6.4 | 3.9 | -39% |
| Reinforcement (Secondary Network) | 33.0 | 60.7 | 4.1 | 12.1 | 194% |
| Fault Level Reinforcement | 14.3 | 32.2 | 1.8 | 6.4 | 261% |
| New Transmission Capacity Charges | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| High Value projects | 17.9 | 21.9 | 2.2 | 4.4 | 96% |
| **Total load related costs** | 135.9 | 164.4 | 17.0 | 32.9 | 94% |

A profile of the LRE expenditure categories is shown below, showing a significant increase over the course of ED2, especially in secondary network reinforcement.

*Chart 8: ENWL load-related capex profile*




We consider that ENWL has provided reasonable justifications for increases in LRE, especially relating to the need to address anticipated LV network capacity constraints to connect low-carbon technologies. However, we were concerned that ENWL's plan had not fully considered the availability of current capacity headroom, and the benefits from flexibility and smart control to enhance network utilisation. As such, the proposed baseline bid appears uncertain and may be overstated – a further proportion of this may be best addressed through uncertainty mechanisms.

We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

### *ii.b. Totex: NLRE*

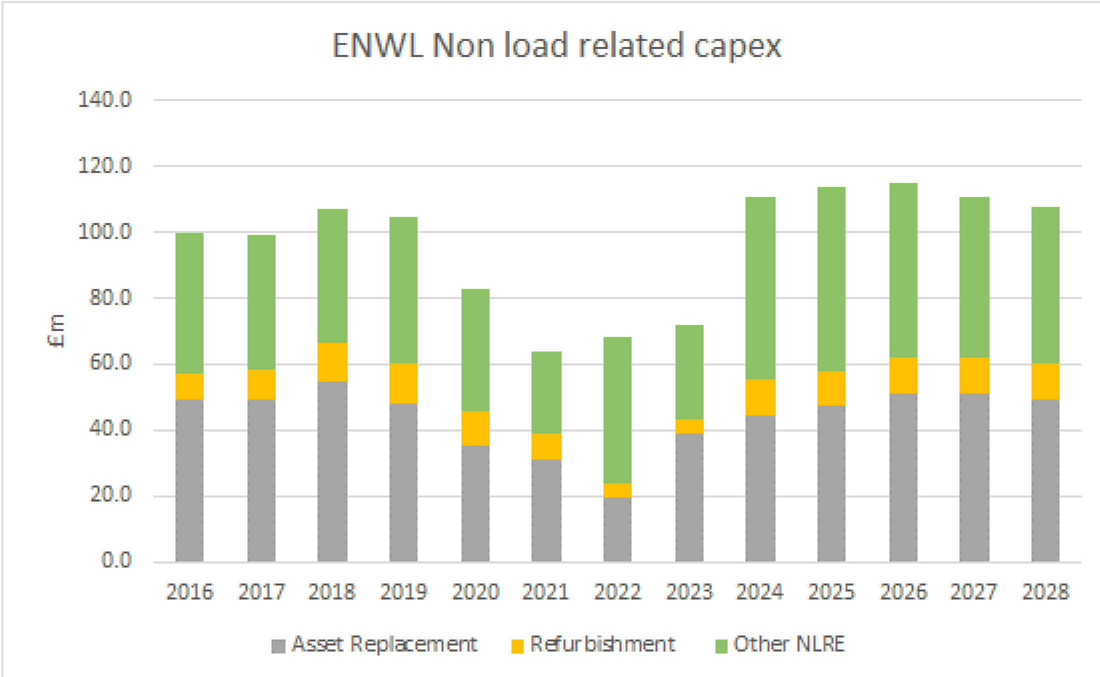
The ENWL bid for baseline NLRE is £558m, which represents a 28% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with reinforcement relating to asset replacement, and operational IT and telecoms showing significant increases in particular.

*Table 44: ENWL non-load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Non Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Diversions (Excluding Rail Electrification) | 36.8 | 18.2 | 4.6 | 3.6 | -21% |
| Diversions Rail Elec | 0.3 | 0.1 | 0.0 | 0.0 | -55% |
| Asset Replacement | 326.0 | 243.1 | 40.7 | 48.6 | 19% |
| Refurbishment | 67.5 | 54.5 | 8.4 | 10.9 | 29% |
| Civil Works Condition Driven | 34.3 | 26.9 | 4.3 | 5.4 | 25% |
| Operational IT and telecoms | 81.6 | 78.2 | 10.2 | 15.6 | 53% |
| Blackstart | 3.5 | 0.0 | 0.4 | 0.0 | -100% |
| BT21CN | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| Legal & Safety | 23.3 | 42.1 | 2.9 | 8.4 | 189% |
| QoS & North of Scotland Resilience | 50.3 | 20.0 | 6.3 | 4.0 | -36% |
| Flood Mitigation | 13.3 | 3.6 | 1.7 | 0.7 | -56% |
| Physical Security | 0.0 | 4.6 | 0.0 | 0.9 | >1000% |
| Rising and Lateral Mains | 12.0 | 17.3 | 1.5 | 3.5 | 131% |
| Overhead Line Clearances | 20.8 | 8.6 | 2.6 | 1.7 | -34% |
| Worst Served Customers | 2.0 | 21.3 | 0.3 | 4.3 | >1000% |
| Environmental Reporting & Losses | 25.8 | 19.8 | 3.2 | 4.0 | 23% |
| HVP | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| **Total non load related capex** | 697.5 | 558.1 | 87.2 | 111.6 | 28% |

A profile of the NLRE expenditure categories from 2016 to 2028 is shown below. It shows a significant decline at the end of ED1 before increasing at the start of ED2. We are concerned that the ED2 increase is due to high-cost asset replacement expenditure being deferred to ED2 and customers having to pay twice for the same replacement work.

*Chart 9: ENWL overall non-load capex profile*




We recognise that there are some upward cost drivers in relation to DSO and network visibility investment, and from accelerated PCB removal. However, we do not think the scale of NLRE expenditure increases for ED2 have been justified given the asset base remains largely the same as for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We note that ENWL are targeting a network risk target of 25.9%, resulting in a closing ED2 risk position of 3% above opening. The forecast monetised risk reduction is 46.8 pence per point. We welcome that ENWL is targeting a closing risk position of 3%, but we do not believe the increase in asset replacement expenditure has been justified.

For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The ENWL profile is shown below:

*Table 45: Low Voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| ENWL | 1047 | 528 | 1400 | -49% | 165% |

We note that the forecast number of LV poles subject to asset replacement during ED2 is significantly greater than ED1 and have examined the EJP in more detail.

In the EJP, we noted the NARM analysis and the aim of maintaining the overall network risk over the RIIO ED2 period. The EJP does not fully explain the reason for the increased rate of deterioration of these wood poles, nor does it consider practical alternatives to direct replacement of the wood poles. While undergrounding has been considered, it is a costly alternative, other less costly options could be available. We ask Ofgem to carefully examine this increased pole replacement programme to ensure that it delivers value for money for consumers.

### *ii.c. Totex: Network operating costs*

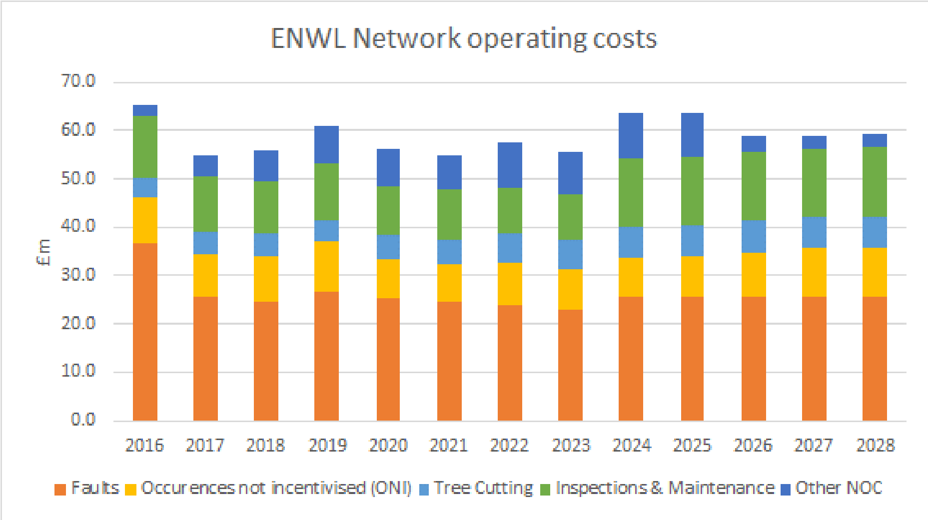
The ENWL bid for network operating costs is £304m, which represents a 6% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with the most significant increases being in Inspections & Maintenance and Tree Cutting. Smart meter costs have decreased.

*Table 46: ENWL network operating cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Opex - Network Operating Costs** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Faults | 210.5 | 127.4 | 26.3 | 25.5 | -3% |
| Severe Weather 1 in 20 | 0.0 | 1.7 | 0.0 | 0.3 | |
| Occurences not incentivised (ONI) | 70.8 | 46.4 | 8.8 | 9.3 | 5% |
| Tree Cutting | 40.0 | 32.2 | 5.0 | 6.4 | 29% |
| Inspections & Maintenance | 86.2 | 71.4 | 10.8 | 14.3 | 32% |
| NOCs Other | 19.2 | 12.1 | 2.4 | 2.4 | 1% |
| Smart Meters | 34.6 | 13.2 | 4.3 | 2.6 | -39% |
| **Total Network Operating Costs** | 461.2 | 304.4 | 57.7 | 60.9 | 6% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown below. The profile increases over the first two years of the ED2 period.

*Chart 10: ENWL overall network operating cost profile*




Overall, we consider that ENWL have provided reasonable justifications in respect of these costs. While a 6% increase in these costs is relatively low, we note that other DNOs have been able to deliver cost reductions in this area and there may be potential for ENWL to also deliver additional savings.

### *ii.d. Totex: Non-operational costs*

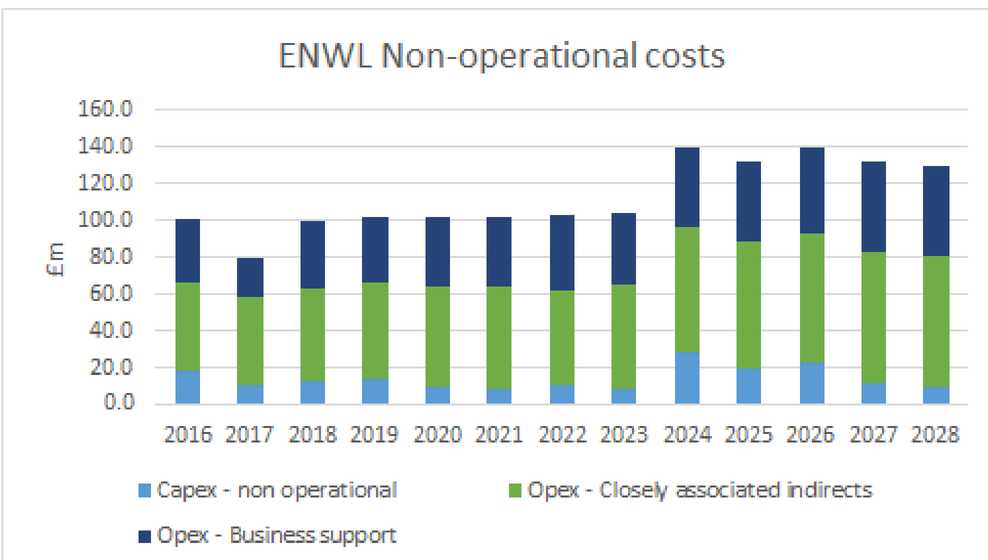
Under this cost grouping we have included business support, closely associated indirect and non-operational capex. The ENWL bid is for £233m of business support costs (an increase of 30%), £349m of closely associated indirects (an increase of 34%), and £92m of non-operational capex (an increase of 60%). The combined increase is 36% which is the highest of all companies. The following table shows the breakdown of these costs by the individual business plan categories.

Table 47: *ENWL non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 122.9 | 104.2 | 15.4 | 20.8 | 36% |
| IT& Telecoms (Business Support) | 125.9 | 104.4 | 15.7 | 20.9 | 33% |
| Property Mgt | 37.4 | 24.3 | 4.7 | 4.9 | 4% |
| **Total Business Support Costs** | 286.2 | 232.9 | 35.8 | 46.6 | 30% |
| **Closely associated indirects** | | | | | |
| Core CAI | 308.4 | 271.6 | 38.6 | 54.3 | 41% |
| Wayleaves | 29.6 | 20.2 | 3.7 | 4.0 | 9% |
| Operational Training (CAI) | 43.2 | 35.3 | 5.4 | 7.1 | 31% |
| Vehicles and Transport (CAI) | 35.3 | 21.5 | 4.4 | 4.3 | -2% |
| **Total CAI** | 416.5 | 348.7 | 52.1 | 69.7 | 34% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 52.1 | 34.9 | 6.5 | 7.0 | 7% |
| Property (Non-Op) | 8.8 | 12.3 | 1.1 | 2.5 | 124% |
| Vehicles and Transport (Non-Op) | 19.7 | 22.5 | 2.5 | 4.5 | 83% |
| Small Tools and Equipment | 12.0 | 22.8 | 1.5 | 4.6 | 202% |
| **Total non-op capex** | 92.6 | 92.5 | 11.6 | 18.5 | 60% |

A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown, below. The profile shows a sharp increase at the start of the ED2 period and continues thereafter.

*Chart 11: ENWL overall non-operational cost profile*




ENWL highlight that these cost increases support the delivery of DSO and digitalisation activities, delivery of their vulnerability strategy, cyber resilience and environmental plans. While details of increases are included, these are high level. We are concerned that efficiency opportunities have not been sought with corresponding rigour, and these non-operational costs may be overstated as a result.

### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. The 0.5% annual ongoing efficiency challenge in the ENWL draft plan has been increased to 1% per annum in the final plan which is welcome. As shown, below, the corresponding forecasts in business plan data tables indicate an overall ED2 saving of 2.9%. ENWL are forecasting real price effects over ED2 that total 4.9%.

*Table 48: ENWL Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| ENWL | 84 | 4.9% | 50 | 2.9% | 1701 |

ENWL's RPE forecasts are amongst the lowest of the DNOs. However, we suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 3.2 (iii) Uncertainty mechanisms

ENWL have detailed several bespoke uncertainty mechanisms in their plan, as shown below. In addition, they have also proposed a load related re-opener, and other uncertainty mechanisms relating to high value projects and IT resilience. Cost estimates are taken from business plan data tables and total £224m or 13% of their totex bid. However, in the time available, we have not been able to fully reconcile the potential uncertainty costs with other information provided in company plans. As such we have commented on the principles relating to these risks and mechanisms rather than the costs proposed.

*Table 49: ENWL UMs*

| Category | Risk addressed | Potential cost |
|---|---|---|
| Providing LCT service solutions | Uncertain load-related investment | £89m; cables not included |
| Wayleave compensation claims | Uncertain expenditure | £55m |
| Ash dieback | Uncertain expenditure | £17m |
| PCB removal | Uncertain expenditure | £25m |
| Moorside power station reinforcement as per ED1 | Uncertain expenditure | Zero if not triggered/needed |
| Net Zero Fund | Net zero facilitation support including LAEP support | Up to £11.4m on a Use it or lose it basis |

| Category | Risk addressed | Potential cost |
|---|---|---|
| Distribution Net Zero fund | Community energy and decarbonisation support | Up to £4.9m on a Use it or lose it basis |

We agree that it would be appropriate to include LRE uncertainty mechanisms but would like to see that these are appropriately calibrated in terms of costs, volumes and triggers. Ofgem should also ensure that investment is delivered and does not provide windfall gains for companies.

We agree with the continuation of the Moorside uncertainty mechanism. For wayleave compensation, ash dieback and PCB removal, we consider that these should be risks best managed by the companies who would be best placed to limit both impact and cost. Similarly, we consider the Net Zero reopeners should be regarded as business as usual activities. Our concern is that these risks may already be adequately funded by the baseline expenditure forecasts and these potential additional cost drivers will only serve to benefit companies.

However, if Ofgem determines that these risks should be included as uncertainty mechanisms, we suggest this should only take place if reasonable expenditure and contingency allowances are not already included in baseline. If applied, the triggers and volume drivers would also need to be appropriately calibrated.

## 3.3 DSO and whole system

### 3.3 (i) DSO and digitalisation strategy

In their DSO plan, ENWL propose the following key initiatives:

- **Visibility –** 100% network visibility, derived from a combination of smart meters and new LV monitoring equipment, and heatmaps for HV by the end of ED1 and for LV by 2025.
- **Flexibility –** unlocking the potential of open and efficient flexibility markets across all voltage levels. The proposed view of ED2 flexibility needs is 1,379MW[11] representing 28% of 2028 peak demand and 182% of the marginal growth in demand between 2020 to 2028 – which seems very high. ENWL are seeking to collaborate with other network and system operators to share data and coordinate the use of flexibility services.
- **Planning –** the annual Distribution Future Electricity Scenarios (DFES) development process will support the development of local area energy plans (LAEPs).
- **Digitalisation –** ENWL aim to accelerate their digitalisation of the energy system and ensuring all stakeholders have open access to their data.

Overall, ENWL are planning £36m of DSO expenditure for ED2 (and 40 DSO staff by 2028) to realise claimed direct benefits of £249m. Our view is that the plan represents a steady evolution from ED1 with a focus on avoided network reinforcement costs and flexibility, but there is little justification to support the claimed benefits.

[11] This represents ENWL's view of the amount of flex that might be needed in ED2 under their flex first approach. It is a forecast for volumes that may be tendered, not the amount that may ultimately be procured.

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

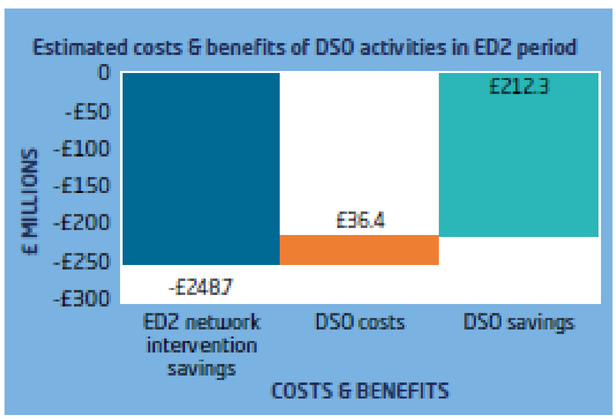
*Table 50: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| ENWL | 4,899 | 759 | 1379 | 28% | 182% | 249 |

In our feedback on the ENWL draft Business Plan we welcomed the progress made on DSO but commented that the delivery plan appeared relatively high level with most delivery dates to be confirmed, and that the flexibility benefits were largely unquantified. We asked that the final plan should include a clear justification for costs and benefits associated with the DSO investments.

The final DSO plan cost-benefit analysis (as shown below) results in network intervention savings of £250m, which after DSO costs totals £212m. Most of these savings (£208m) are attributed to more accurate network planning from utilising more granular forecasts from the ATLAS methodology. Around £11m of benefits are estimated from the use of flexibility markets.

*Figure 1: ENWL estimated total savings from DSO activities in ES2 period*




ENWL propose to implement the DSO model by establishing a separate DSO Directorate, reporting to the Chief Executive, which will undertake a range of initiatives including DSO functions for planning and network development, network operation, flexibility market development and data sharing. A new DSO stakeholder panel and compliance officer are also proposed. The plan also includes the key actions within the DSO transition plan to deliver the baseline expectations.

We welcome the progress that ENWL have taken to assess the costs and benefits of DSO activities, but we are concerned that the estimates for network investment reduction are not justified and are uncertain. Flexibility benefits appear low. While we support the proposed DSO development plan, there appears to be a significant risk that it will not realise the anticipated or potential benefits.

***Digitalisation***

ENWL's plan for ED2 identifies digitalisation initiatives based around the Energy Data Task Force Recommendations. The plan seeks to deliver the following digitalisation principles, with detailed actions due to be delivered by June 2022. Future actions listed below are also highlighted, but without a clear description or delivery programme:

- Prioritise benefits to stakeholders who pay for ENWL services;
- Invest in digital services that work towards a defined vision;
- Take advantage of opportunities to deliver benefits early;
- Make it easy to understand products and services;
- Publish digitalisation action plan;
- Determine shared understanding of success and performance measures; and,
- Co-ordinate with wider eco system of products and services.

Overall, the digitalisation plan appears to have improved since the draft plan, providing additional detail on digitalisation costs and delivery. There is an open platform vision which focuses on network utilisation and forecasting. This would appear to provide a good basis for inter-market alignment and being outward facing. We remain concerned about the ability to deliver and how the necessary capabilities will be established.

#### 3.3 (ii) Whole system strategy

During ED2, ENWL propose to perform a key role of coordination and cooperation with regional stakeholders, other industry sectors and other energy providers to develop whole system outcomes. The plan proposes to:

- Enhance existing data exchange activities in the electricity sector;
- Use energy efficiency measures to reduce demand; and,
- Collaborate across heat, transport and customer support systems.

We welcome ENWL's proposals to work more closely with Local Authorities and community groups to help them transition to Net Zero. This proposed approach is high level and appears to largely maintain business as usual activities rather than the desired step change needed to deliver whole system benefits.

Overall, the whole system plan appears to be quite high level and is predominantly focused on business as usual electricity system activities. The identification and delivery of whole system benefits appear limited and uncertain.

### 3.4 Other outputs

#### 3.4 (i) Environmental Action Plan

ENWL have made considerable progress in refining their EAP since July. The plan now articulates ENWL's vision of leadership in carbon reduction more clearly. Goals are clearly articulated and linked to UN SDGs. However, we still feel that the EAP could be developed (or perhaps show more of the working which underlies it). There is little or no benchmarking or reference to best practice and, as with other plans, limited optioneering.

ENWL have made progress on adopting an SBT and now propose a 1.5°C trajectory for SBT for scopes 1, 2 and 3. However, the EAP is not very advanced in assessment of scope 3 emissions, so it is far from clear how this will be achieved. Its reference to non-supply chain emissions, in particular, is both unclear and seems to suggest a lack of understanding of what is required for the SBT process. The SBT end date (63% reduction by 2035) is clear but not the intermediate target. It appears that a 2038 Net Zero target was the most ambitious put forward to stakeholders, so the level of ambition which could have been supported was not really tested.

ENWL's proposed actions to achieve a reduction in controllable BCF are set out with costings. It would be helpful to have a clear indication, as other plans do, of the contribution various categories of emission make to the total BCF and more information about the factors determining choice of measures.

On $SF_6$, the target for leakage is now explained and ENWL have plans both to adopt non-$SF_6$ solutions as these technologies emerge, and indeed to collaborate to accelerate their availability. The plan already commits to use them at shared GSPs with NG and 11/6.6kV switchboards; this is welcomed.

In relation to losses, ENWL have pioneered two CVPs, CLASS and Smart Street (the latter including a focus on vulnerability – see below), both partly designed to avoid losses through voltage management. These CVPs are further discussed in ENWL's CVP section. We are pleased to note that they acknowledge that losses are part of their BCF and have included a specific loss reduction target as one of their goals.

Steps to measure embodied carbon now show more ambition in terms of timescale than in their draft plan, which is welcome.

### 3.4 (ii) Vulnerability strategy

This is a competent strategy, based on a sophisticated use of data and built around principles co-created with its Consumer Vulnerability Advisory panel.

It remains the only strategy to set both 'target' and 'stretch' levels for its commitments. This may be resolved if Ofgem sets targets for all DNOs on commonly-agreed metrics, but, for now, we remain unclear about what these different levels mean customers can expect to be delivered in the period. For example, its base target for sign-ups to its PSR appears to be one of the lowest of all the DNOs, at 60% of all eligible homes by the end of ED2. But its 'stretch' target of 80% is among the most ambitious. More positively, it is one of a minority of DNOs to set a more outcomes-based quality target for its work to update the PSR, saying it will ensure that 30% of customer details are either updated or confirmed as correct (from 16% currently).

In terms of power cut support, ENWL's vulnerability strategy places a stronger emphasis than others' on avoiding the need for support by improving reliability for customers in vulnerable circumstances. This is a logical approach but needs to be considered in the context of how effectively efforts like this can be targeted and what levels of investment are proportionate (see the following section on Reliability for more on this). ENWL also commit to offer home welfare visits proactively to customers in vulnerable circumstances during power cuts lasting more than 12 hours.

On fuel poverty, ENWL are planning a five- to six-fold increase in the number of customers it supports each year – from 4k a year in 2019/20 to between 25k and 30k customers a year in ED2.

They are also committing to increase the value of benefits delivered per customer from £89 now to between £125 to £175 in ED2. In July, we challenged ENWL to provide evidence that these targets could be delivered. ENWL's plan now shows that it is significantly ramping up the scale of its referrals in the later years of ED1 – aiming to achieve 15,000 in 2021/22. This is encouraging but we would also have liked to see evidence that, as ENWL scale up the volume, they are able to deliver the value of benefits per customer promised by the plan.

In terms of supporting customers with the energy transition, ENWL seem uncertain at this point how they can best help. Their strategy focuses on building insight and understanding in this area, which is reasonable, but this is activity that many other DNOs have already carried out. They are introducing a £250k per annum fund to invite projects to support removing barriers in this area. And we welcome the cultural focus on acknowledging that one thing a DNO should certainly do is to understand and remove any barriers within its direct control – for example, through redesigning services and building vulnerability 'risk assessments' into their business as usual activities. We hope ENWL will report openly on its learnings in this area for the benefit of all DNOs' customers.

ENWL's approach to collaboration with other utilities includes data sharing related to their PSR, but also considers new research projects and partnerships. They also recognise the potential for a national service to provide a PSR.

### 3.4 (iii) Reliability

ENWL are already one of the best performing networks for reliability in ED1 and their plan is targeting among the most stretching and extensive further improvements for ED2. If these are delivered in practice, then they would be one of three networks whose customers experience half as many power cuts as customers of other DNOs. When Ofgem sets the final IIS targets for ENWL (and all DNOs), it will need to ensure that the costs and rewards they drive represent good value for customers when weighed against affordability and the other investments that are needed in ED2. It was unclear to us whether this balance has been struck appropriately in ENWL's plan. In terms of worst-served customers, ENWL have clarified their target for ED2, and says that they will aim to have no customers that meet this definition by 2028. They have also included in their baseline costs, £20m to improve reliability for customers in vulnerable circumstances. Of this, £3m would reduce the risk of a power cut (although we were not clear to what extent) for 844 customers at a cost of c.£3,400 per customer. The larger part would mitigate the impact of HV power cuts for 56 sites (such as hospitals) and c.16,600 customers at a cost of £1k per vulnerable customer.

*Table 51: ENWL's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with ENWL's performance in ED1.*

| | ED2 Average | | | | % change from ED1 Average | | | |
|---|---|---|---|---|---|---|---|---|
| | CI | CML | CI | CML | CI | CML | CI | CML |
| | (incl. exceptional) | | (excl. exceptional) | | (incl. exceptional) | | (excl. exceptional) | |
| ENWL | 25 | 25 | 22 | 22 | -28% | -35% | -28% | -26% |

## 3.5 Consumer Value Propositions

*CVP1: Smart Street – not recommended*

In ENWL's draft plan, Smart Street was presented as a vulnerability initiative but has now been reclassified as a whole systems CVP (with benefits for vulnerable customers).

The ENWL CVP proposition is that they should invest an additional £78m to the £18m already spent on Smart Street to deliver claimed benefits of around £450m[12] over the lifetime of the assets. These benefits would be targeted at customers in vulnerable circumstances. In July, we challenged ENWL on the claimed benefits and on how effectively it could target this technology on vulnerable households. Their final plan acknowledges that any targeting would be limited; they estimate that 16% of customers benefiting from the programme would be on their PSR, compared with 12% of PSR customers in their base as a whole. The Challenge Group welcomes the additional information that ENWL has provided on this since their draft plan, including a report prepared by Kelvatek. However, the Challenge Group still have a number of concerns. While we agree that voltage management is barely noticed by customers and that power consumption will decrease with a voltage reduction, we do not consider that sufficient evidence has been provided to justify the claimed benefits for this large investment.

- **Firstly, we consider that future energy savings may be overestimated.** ENWL assume in their cost-benefit assessment that there is no reduction in customer benefits over time, whereas a trend for growth of consumer appliances and devices, e.g. LED lighting, that better control voltage and energy consumption will reduce this benefit. Customer appliances that use electricity for heating will not see any benefit from this measure. The consumption evidence to support the assumptions was based on data collected in 2015 to 2017, and may not be representative of future assumptions. In addition, the expected growth of low carbon technologies on LV networks may impact the available benefits.
- **Secondly, that there are better value and better targeted alternatives for vulnerable customers to conserve energy**. ENWL claim that an investment of c.£350 for each of the 250,000 targeted customers will deliver savings of up to £60 per annum paid through increased charges to other ENWL customers. But this benefit and payback period appears highly uncertain and will depend on many factors including individual customer energy decisions. This does not appear to offer as much value to vulnerable customers as other energy saving measures such as insulation or LED light bulbs and other appliances which control energy consumption – these have shorter paybacks.

While we welcome ENWL's ambition to use innovative ways of reducing costs for consumers, we do not consider that the evidence has been provided to support the benefits or address the risks arising from such a large investment. As such, we do not consider a CVP incentive is appropriate.

*CVP2: CLASS – not recommended*

CLASS is a technology that provides a fast response service to the ESO by reducing voltage. Subject to regulatory decision, it competes with other fast response service providers in a competitive market and is used when the ESO judge it to the most efficient.

[12] The claimed energy savings are up to 8% per household (equivalent to £60 p.a.).

The Challenge Group notes that ENWL are not requesting any additional funding for CLASS and agree that, assuming they operate in a competitive market, this is the correct treatment as it would distort the level playing field for other providers of the fast response service. Any additional reward, paid by consumers, would be disproportionate and anti-competitive.

## 3.6 Finance

We commented that ENWL's draft plan was unclear as to whether modelling had been carried out on the basis of an effective cost of equity allowance of 4.65% (being 4.4% plus 25bps outperformance allowance). That position is now fully clarified. We also commented on ENWL's financeability 'tests' and we note that a change has been made which addresses one of our principal concerns: a minimum cost of equity allowance of 5.81% which, with an Ofgem W/A of 4.4%, meant it was a test which it was impossible to pass. We still have considerable reservations about the emphasis given to the ENWL tests in its BP: it would have been more helpful if the plan had focused on the Ofgem required tests. However, we note that ENWL have presented a full suite of results for the Ofgem required stress tests (Annex 28B), in compliance with the SSMD. We also note that, in general and despite our reservations about ENWL's presentation of their own stress tests, the tone of the BUSINESS PLAN is helpful and positive, with an appropriate emphasis on exploring mitigating actions.

ENWL say that they are targeting a Baa1/BBB+ rating (and, indeed, that an expectation of achieving at least that rating in the unstressed base case is its first test of financeability). We accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status. However, we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. We regard Baa1/BBB+ as at the upper end of the acceptable target range. Certainly we do not consider that a company needs to demonstrate an expectation of a Baa1/BBB+ rating to be considered financeable.

As the only 'singleton' DNO, ENWL have some specific problems which are different from those faced by the other DNOs.These are principally in connection with debt finance and stem from their small size relative to other companies in the sector and the fact that that size is combined with independent ownership. Because the SSMD requires that, in the modelling of the Notional Company, the cost of debt should be deemed to equal the cost of debt allowance, these problems manifest themselves more clearly in the modelling of the Actual Company, in which actual debt costs have to be used. For most DNOs, the Ofgem cost of debt assumption at 2.09% is very similar to the actual cost of debt and the Ofgem assumption has been used in the Actual as well as the Notional Company modelling. In the case of ENWL, historic debt costs are out of line with the sector as a whole and hence with Ofgem's cost of debt assumption. This may apply, although to a much more limited extent, to future debt costs. ENWL argue that their problems result from the fact that the amount of debt which they require to fund their activities is relatively small and that this in turn means that they can only access the market relatively infrequently in order that each issuance is of 'benchmark' size (and hence competitively priced). ENWL argues that it is difficult to achieve optimal timing of these relatively infrequent issuances in terms of market conditions and also that it makes it difficult to mirror the 17-year trailing average on which the Ofgem cost of debt W/A is based. It is clear that the company has made issuances in the past on sub-optimal terms (some of which are acknowledged as inefficiently incurred debt). However, they have not needed special provisions to cover these costs in ED1 and we note that the most expensive of their bonds runs off in 2026: all else being equal, therefore, we consider that they can reasonably expect the position to improve, rather than the reverse.

We think it is important to consider ENWL's comments about their size and the difficulty which they have achieving 'benchmark' size for their issuances in a wider context than simply the other DNOs: there are water and gas distribution companies which are both comparable in size to, and smaller than, ENWL which have not been accorded special treatment by their respective regulators. We do not accept all of ENWL's arguments but it is certainly true that, because of its size, they have a problem with the cost of its debt funding which is not shared with the rest of the sector and which they say amounts to £90-95m over the ED2 period. This will require extensive use of Ofgem's proposed mitigating measures (as, in fairness, ENWL appear to accept). Their problems are exacerbated by the fact that 60% of their debt has been contracted on an RPI index-linked basis. We accept that this means that the RPI/CPIH (CPI, including owner-occupied housing costs) risk, which is immaterial (or non-existent) for other DNOs, is substantial for ENWL. However, we do not consider that the results of their decisions about the basis on which they have elected to contract debt should be borne by consumers through a higher cost of capital allowance.

We have analysed ENWL's financeability on the basis of the stress testing required by Ofgem rather than their own tests (the analysis of which we find unhelpfully interspersed in the plan with ENWL's own four tests). It is clear from the results shown that the Notional Company is borderline for financeability with a cost of equity allowance of 4.65%: it achieves Baa2 or BBB+/BBB which is investment grade in the base case and, even in the most difficult downside scenario (low RoRE), is borderline investment grade. It should be kept in mind that these results are flattered by the fact that they are based on the Ofgem assumption that the cost of debt equates to the cost of debt allowance, which is obviously not realistic in the case of ENWL. On the other hand, the case does not include any of ENWL's proposed mitigating measures. The plan states that a 4.79% cost of equity allowance is the minimum required to achieve a BBB+ rating for the Notional Company. This may well be the case but we reiterate that, although Baa1/BBB+ may be ENWL's target rating, it is not necessary to achieve financeability and that 4.79% is only 14 basis points above Ofgem's cost of equity W/A. This 14 basis points gap is not insignificant but in our view could well be bridgeable with full deployment of Ofgem's 'levers' to assist financeability.

The results for the Actual Company based on Ofgem's W/As (which, for the Actual Company obviously include actual projected debt costs), are difficult with results either only just above or marginally below investment grade (Baa2/Baa3 or BBB+/BBB in the Base Case and Ba1 or BBB/BBB- in the downside RoRE case). These results do not, however, incorporate mitigating actions and we are not persuaded that there is no basis for improving them other than changes to the cost of capital allowances.

ENWL propose a number of mitigating actions to help it to achieve financeability. One of these is a higher cost of equity allowance. We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions. We do not, in any case, consider that an adjustment to the cost of equity allowance is the right way to deal with a problem which, as ENWL rightly identifies, relates to the cost of their debt. ENWL also propose an adjustment to the cost of debt allowance. We consider Ofgem's W/A for the cost of debt to be well evidenced and appropriate for the DNO sector as a whole. We accept that ENWL's debt position is out of line with the rest of the sector and that, as a result, the Ofgem W/A does not cover their borrowing costs. We have rejected the concept of one-off adjustment to the cost of equity allowance to recognise the concerns of individual DNOs and take the same view in relation to the cost of debt allowance. We are not, in any case, clear that ENWL has carried out exhaustive analysis of all measures to aid financeability other than a change in the cost of capital allowances.

ENWL propose that the Notional Company should be analysed at the gearing applicable in ED1, which is 65%. A change in gearing is one of the levers suggested in the SSMD and which we accept may be helpful (we also acknowledge the potential tax clawback issues associated with deleveraging to 60%). In addition, ENWL propose to reduce the regulatory capitalisation rate to 65% from its 'natural' rate of 68% (though it does not propose any change in the depreciation period). Again, changes to both capitalisation rates and depreciation periods are levers recommended in the SSMD. Importantly, ENWL have based their analysis on making no dividend payments at all during ED2. They have not, however, modelled any issuance of new equity (although they say that they will reconsider this position at the time, and in the light, of the final determination).

ENWL's Board Assurance Statement is explicit that 'the Board cannot say the business plan is financeable on the basis of Ofgem's Working Assumptions for either the notional or actual company, without some changes to these assumptions'. We accept that ENWL faces some financeability challenges but believe it is important that modelling which incorporates all of the mitigating actions which they discuss is properly analysed: the company's position is less comfortable than that of the other DNOs, but we do not consider, on the basis of the evidence currently available, that it is out of the question for the company to achieve an acceptable level of financeability on the basis of Ofgem's W/As for the allowances for the cost of both equity and debt.

# 4. Company report – NPg

As a summary, we have assigned NPg's Business Plan the following ratings:

*Table 52: NPg BP scores*[13]

| | |
|---|---|
| Track record from RIIO-ED1 | 3 |
| Scenarios and forecasts | 4 |
| Totex: LRE, incl. anticipatory investment | 2 |
| Totex: NLRE, incl. asset health | 3 |
| Totex: Network operating costs | 4 |
| Totex: Non-operational costs | 2 |
| Totex: Ongoing efficiency and RPE | 2 |
| Totex: Uncertainty mechanisms | 3 |
| Outputs: DSO and digitalisation strategy | 2 |
| Outputs: Whole system strategy | 2 |
| Outputs: EAP | 3 |
| Outputs: Vulnerability strategy | 3 |
| Outputs: Reliability | 3 |
| Finance | 3 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of NPg's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 245% from ED1 levels and includes anticipatory investment for ED3. We are concerned this may result in stranded assets or limit cheaper flexibility options.
- **DSO and whole system –** NPg are targeting annual DNO-contracted flexibility actions of 138MW, delivering benefits of £155m over ED2. We are concerned that these benefits may not be realised and also that the potential benefits may not be fully reflected in load-related capex forecasts.
- **Costs –** Baseline totex has reduced by £80m since the draft plan but is still forecast to increase by 36% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that cost increases for a largely similar underlying asset base are unjustified.
- **Risks and uncertainty –** NPg have proposed only load-related uncertainty mechanisms which could add £224m or 13% of totex. We are concerned that some of these UM costs may duplicate those already included in baseline expenditure.
- **Vulnerability –** NPg's target to register 50% of eligible customers on its PSR by 2028 appears to be off the pace. We would challenge NPg to investigate what more it can do to improve performance in this vital area.
- **Finance –** In our view, NPg's modelling provides a clear demonstration of the financeability of both their licensees on the basis of Ofgem's Working Assumptions

[13] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

(W/As) for the cost of capital. We would like to understand what grounds the Board has for now saying that this is not the case, and why NPg has not shown the results of a full exploration of all Ofgem's 'levers' for improving financeability, particularly in relation to dividend restraint or new equity, and which we consider could well result in the BP being financeable with a cost of equity below 4.65% (to the benefit of NPg's customers).

## 4.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

Key performance measures are shown in the tables, below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 53: NPg ED1 performance summary*

| **ED1 performance (2021 RRP)** | **NPg** |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 1.7% |
| Customer service (BMCS) | 0.4% |
| Time to connect (TTC) | 0.1% |
| **Output incentives total** | 2.2% |
| | |
| **Totex efficiency incentives** | 0.0% |
| **Operational RoRE** | 8.0% |

**ED1 - Totex (2021 PCFM)**

| **£m (2012/13 prices)** | **NPg** |
|---|---|
| Totex allowance | 3011 |
| Totex actual/forecast | 2981 |
| % totex (under)/overspend | (1%) |
| % LRE (under)/over spend | (19%) |
| % Totex (excl. LRE) (under)/overspend | 0% |

NPg advise that they expect their overall ED1 outturn expenditure to be in line with allowances.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) performance is amongst the highest of all DNOs but the customer service incentive (BMCS) is mid-ranking.

## 4.2 Costs, scenarios and forecasts

### 4.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios that NPg have examined and note that they are using their 'Planning Scenario' as the Best View scenario, which is based on a highly electrified decarbonisation pathway. We welcome that these scenarios appear to be consistent with Net Zero targets. We also note that the Planning Scenario is at the higher end of all the pathways considered and is unchanged from the draft Business Plan submitted in July.

By the end of ED2, NPg forecast that they will connect:

- 941k EVs and 309k heat pumps under their Planning scenario; and,
- 1,139k EVs and 334k heat pumps under their Upper scenario.

These scenarios are presented below as 'Best View' and 'Upper View'

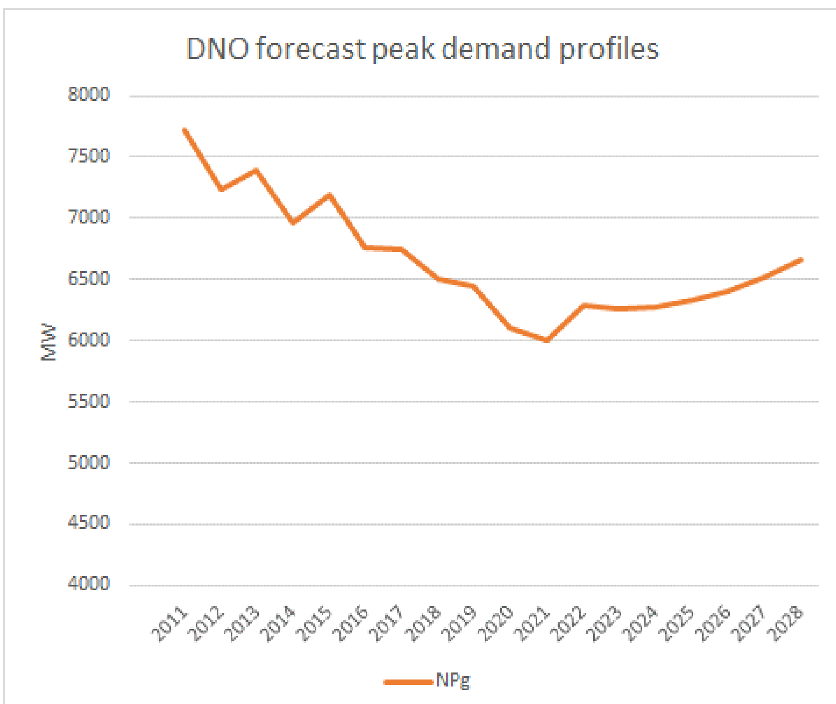
*Table 54: NPg low-carbon technology scenarios*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| NPg | 941 | 24% | 309 | 8% | 1139 | 28% | 334 | 8% |

NPg have around 13% of the networks' total customer base. The forecast number of EVs and heat pumps in the Planning scenario across this customer base in 2028 is broadly in line with the ESO FES 2021 Consumer Transformation or Leading The Way scenarios, which forecast about 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers.

The NPg submission of demand profiles in the BPDTs (shown below) shows an increase of around 9% between 2020 and 2028, which is broadly in line with the ESO 2021 Customer Transformation scenario increase of 11%.

*Chart 12: NPg forecast peak demand profile*




In their business plan, as shown below, NPg have assumed their peak demand will be supressed from 2025 by time-of-use tariffs and the deployment of flexible devices such as smart EV. The profile in NPg's plan (shown below) is reasonably consistent with the profile we have derived above.

*Chart 13: NPg plan forecast peak demand profile*

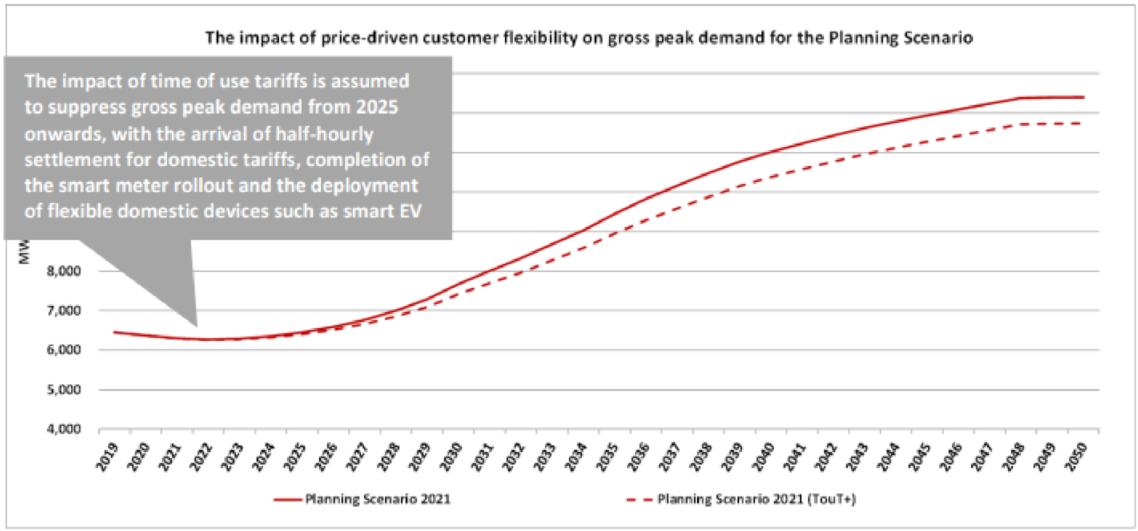



*Figure 23: Impact of price driven customer flexibility*

Overall, we consider that NPg have undertaken effective scenario planning, taking account of upward and downward demand drivers, and have provided scenario assumptions that are consistent with relevant national forecasts.

### 4.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered; and,
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages.

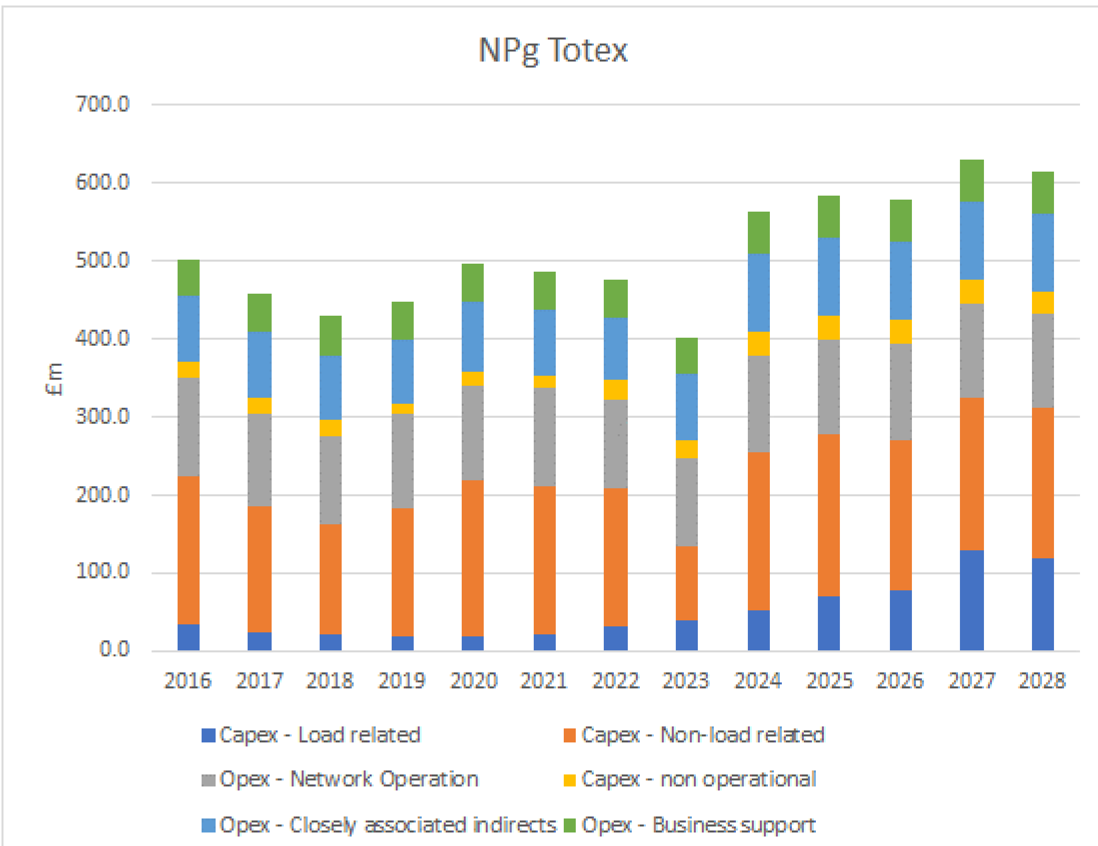
The NPg ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £2,970m and is a 28% increase on the annual average expenditure rate during ED1. We welcome the fact that the forecast has reduced from the £3,047m figure submitted in the NPg draft plan. The following table compares the NPg cost submissions between ED1 actuals/forecasts and ED2 forecasts. It also compares the draft and final plans[14].

*Table 55: NPg overall totex comparison*

| NPg | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| Overall | ED1 | ED2 | ED1 | ED2 | ED1-ED2 | ED1 | ED2 | ED1 | ED2 | ED1-ED2 |
| Capex - Load related | 207.7 | 448.5 | 26.0 | 89.7 | 245% | 192.9 | 598.3 | 24.1 | 119.7 | 396% |
| Capex - Non-load related | 1321.0 | 992.5 | 165.1 | 198.5 | 20% | 1294.6 | 931.7 | 161.8 | 186.3 | 15% |
| Opex - Network Operation | 953.1 | 609.6 | 119.1 | 121.9 | 2% | 961.0 | 603.1 | 120.1 | 120.6 | 0% |
| Capex - non operational | 152.5 | 149.8 | 19.1 | 30.0 | 57% | 150.2 | 151.6 | 18.8 | 30.3 | 62% |
| Opex - Closely associated indirects | 676.2 | 500.4 | 84.5 | 100.1 | 18% | 677.4 | 493.2 | 84.7 | 98.6 | 16% |
| Opex - Business support | 388.4 | 269.4 | 48.5 | 53.9 | 11% | 390.9 | 269.4 | 48.9 | 53.9 | 10% |
| **BPDT Totex** | 3698.9 | 2970.2 | 462.4 | 594.0 | 28% | 3667.1 | 3047.2 | 458.4 | 609.4 | 33% |
| **Baseline totex after OE/RPE adjustments** | | | 455.4 | 617.2 | 36% | | | | | |
| **Baseline totex with UMs (excl. Access SCR)** | | | 455.4 | 663.2 | 46% | | | | | |

A profile of the totex and main expenditure categories is shown, below. It shows a significant increase at the start of ED2, especially in non-load capex.

*Chart 14: NPg overall totex profile*




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for most ongoing expenditure, and we have scrutinised reasons for increases from these

[14] Note: These totex figures exclude 'other costs outside the price control' The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.

levels. Our assessments for these individual cost categories are set out below, seeking to understand the justifications for these potential increases.

### *ii.a. Totex: LRE*

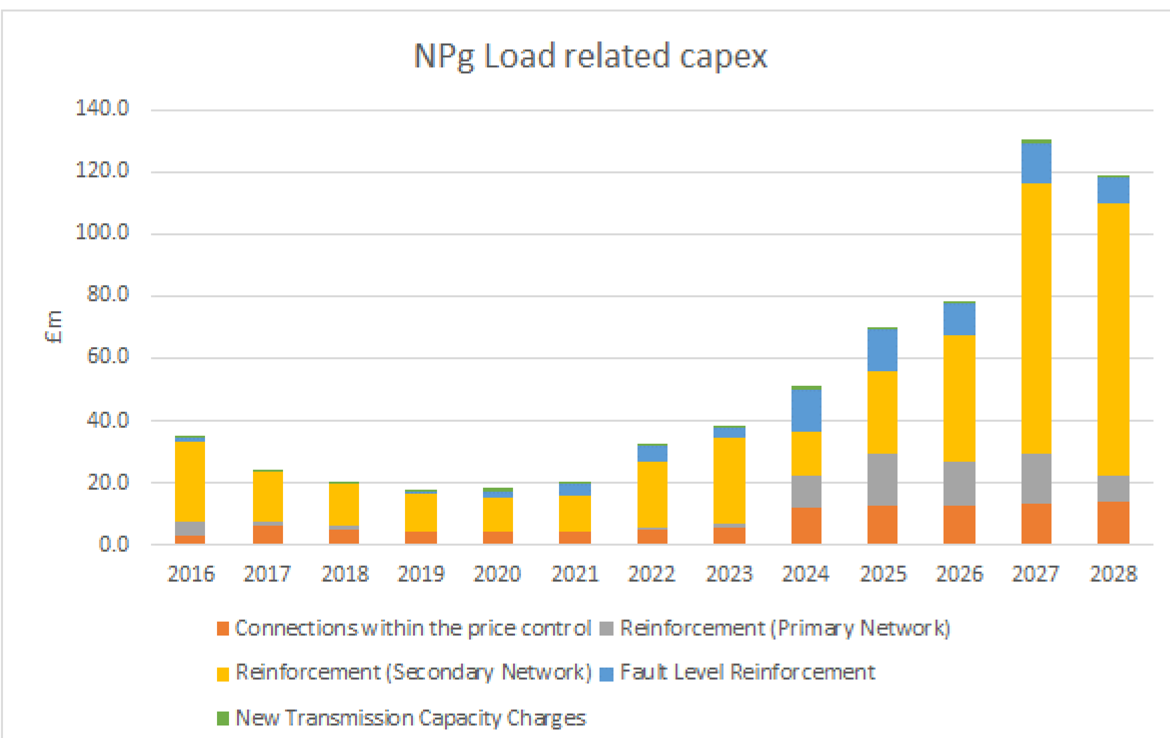
The NPg bid for baseline LRE is £448m, which represents a 245% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual categories. Reinforcement relating to primary and secondary networks, fault level reinforcement and connections all show significant increases.

*Table 56: NPg load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Connections within the price control | 37.1 | 64.8 | 4.6 | 13.0 | 179% |
| Reinforcement (Primary Network) | 8.5 | 65.2 | 1.1 | 13.0 | 1122% |
| Reinforcement (Secondary Network) | 139.4 | 255.9 | 17.4 | 51.2 | 194% |
| Fault Level Reinforcement | 16.1 | 58.7 | 2.0 | 11.7 | 484% |
| New Transmission Capacity Charges | 6.6 | 3.9 | 0.8 | 0.8 | -6% |
| **Total load related costs** | 207.7 | 448.5 | 26.0 | 89.7 | 245% |

A profile of the LRE expenditure categories is shown below. It shows a significant increase over the course of ED2, especially in secondary network reinforcement.

*Chart 15: NPg load-related capex profile*




We have examined the evidence provided by NPg, but are concerned that their plan does not fully exploit current capacity headroom, and the benefits from flexibility and smart control to enhance network utilisation. We do not consider that NPg has provided reasonable justifications for such large increases in LRE. We are concerned that such a rapid expansion ahead of need, and before network visibility, flexibility and smart control are in place, risks delivering higher-cost solutions. We consider that an increased allocation of NPg's LRE to uncertainty mechanisms may be an appropriate way of addressing this issue.

We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

### *ii.b. Totex: NLRE*

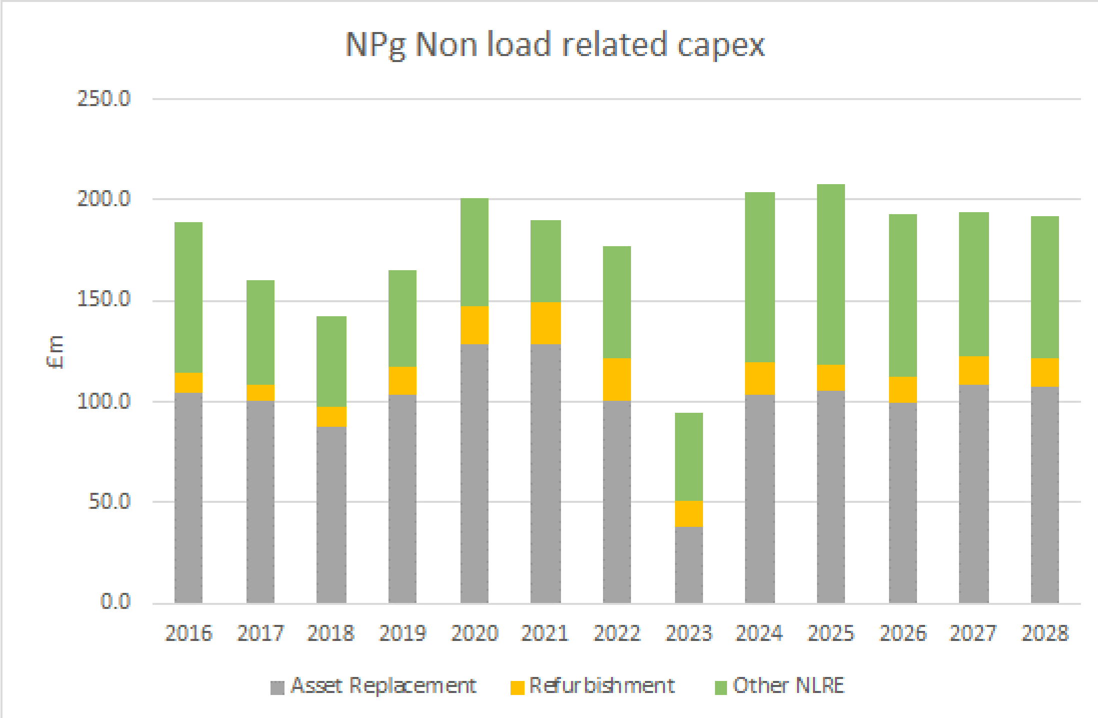
The NPg bid for baseline NLRE is £988m, which represents a 22% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 57: NPg non-load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Non Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Diversions (Excluding Rail Electrification) | 98.6 | 64.0 | 12.3 | 12.8 | 4% |
| Diversions Rail Elec | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| Asset Replacement | 792.3 | 526.0 | 99.0 | 105.2 | 6% |
| Refurbishment | 116.1 | 68.1 | 14.5 | 13.6 | -6% |
| Civil Works Condition Driven | 37.4 | 29.6 | 4.7 | 5.9 | 27% |
| Operational IT and telecoms | 52.2 | 94.9 | 6.5 | 19.0 | 191% |
| Blackstart | 11.1 | 0.0 | 1.4 | 0.0 | -100% |
| BT21CN | 0.8 | 0.0 | 0.1 | 0.0 | -100% |
| Legal & Safety | 53.6 | 46.8 | 6.7 | 9.4 | 40% |
| QoS & North of Scotland Resilience | 37.3 | 61.1 | 4.7 | 12.2 | 162% |
| Flood Mitigation | 48.1 | 5.7 | 6.0 | 1.1 | -81% |
| Physical Security | 6.1 | 0.0 | 0.8 | 0.0 | -100% |
| Rising and Lateral Mains | 2.6 | 13.3 | 0.3 | 2.7 | 713% |
| Overhead Line Clearances | 9.7 | 22.7 | 1.2 | 4.5 | 276% |
| Worst Served Customers | 0.0 | 4.0 | 0.0 | 0.8 | n/a |
| Environmental Reporting & Losses | 25.4 | 56.2 | 3.2 | 11.2 | 254% |
| HVP | 29.8 | 0.0 | 3.7 | 0.0 | n/a |
| **Total non load related capex** | 1321.0 | 992.5 | 165.1 | 198.5 | 20% |

A profile of the NLRE expenditure categories from 2016 to 2028 is shown, below. It shows a significant decline at the end of ED1 before increasing at the start of ED2. We note that NPg state that this is due to front-end loading of their investment programme to the benefit of customers. However, we are concerned that the ED2 increase could be due to high-cost asset replacement expenditure being deferred from ED1. This could mean customers having to pay more than necessary. We suggest that Ofgem should investigate this further.

*Chart 16: NPg overall non-load capex profile*




We recognise that there are some upward cost drivers in relation to DSO and network visibility investment which appear to be reflected in operational IT and telecoms. NPg point out that their asset degradation is not linear, and they anticipate an increase in asset risk in ED2. We note that their asset replacement expenditure shows a relatively low increase of 6%. But the overall NLRE when all individual elements are taken into account, increases by 22%, which we do not think has been justified given the underlying asset base remains largely similar to that for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We welcome that NPg are targeting a network risk target of 24.5%, resulting in a closing ED2 position of 2.8% above opening. The forecast monetised risk reduction is 43.3 pence per point. We note the low-risk point cost relative to other DNOs, but still have concerns whether the increase in asset replacement expenditure has been justified.

For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The NPg profile is shown below:

*Table 58: Low voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| NPgN | 1317 | 582 | 2400 | -56% | 312% |
| NPgY | 1321 | 405 | 1697 | -69% | 319% |
| TOTAL | 2638 | 987 | 4097 | -63% | 315% |

The NPg forecast number of LV poles subject to asset replacement during ED2 is significantly greater than ED1, and we have examined their EJP in more detail.

We note that the projection of asset health is informed by the age of the poles and the condition assessment information collected by foot patrols. While there may be particular problems with wood poles treated with AC500, we are concerned that this step increase (>300%) in asset replacement hasn't been fully justified. The EJP claims that, if replaced, there will be a reduction in repair costs which does not appear to have been quantified. We ask Ofgem to carefully examine this increased pole replacement programme to ensure that it delivers value for money for consumers.

We welcome that, in the constrained parts of the network, the opportunity will be taken to increase the capacity of the circuits when a conductor is replaced.

### *ii.c. Totex: Network operating costs*

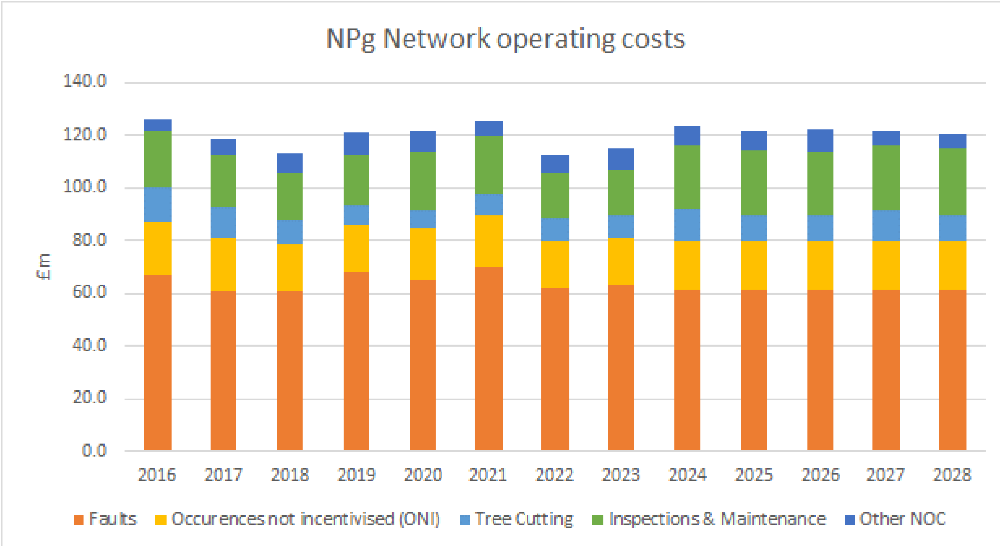
The NPg bid for network operating costs is £610m, which represents a 2% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with the most significant increases being in Inspections & Maintenance and Tree Cutting. Smart meter costs have decreased.

*Table 59: NPg network operating cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Opex - Network Operating Costs** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Faults | 515.7 | 307.8 | 64.5 | 61.6 | -5% |
| Severe Weather 1 in 20 | 0.0 | 10.0 | 0.0 | 2.0 | |
| ONIs | 152.9 | 91.9 | 19.1 | 18.4 | -4% |
| Tree Cutting | 73.4 | 53.4 | 9.2 | 10.7 | 16% |
| I&M | 156.1 | 121.8 | 19.5 | 24.4 | 25% |
| NOCs Other | 22.4 | 18.6 | 2.8 | 3.7 | 33% |
| Smart Meters | 32.7 | 6.0 | 4.1 | 1.2 | -71% |
| **Total Network Operating Costs** | 953.1 | 609.6 | 119.1 | 121.9 | 2% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown below. The profile stays stable over the ED2 period.

*Chart 17: NPg overall network operating cost profile*




Overall, we consider that NPg have provided reasonable justifications in respect of these costs. While a 2% increase in these costs is relatively low, we note that other DNOs have been able to deliver cost reductions in this area and there may be potential for NPg to also deliver additional savings.

### ii.d. Totex: Non-operational costs

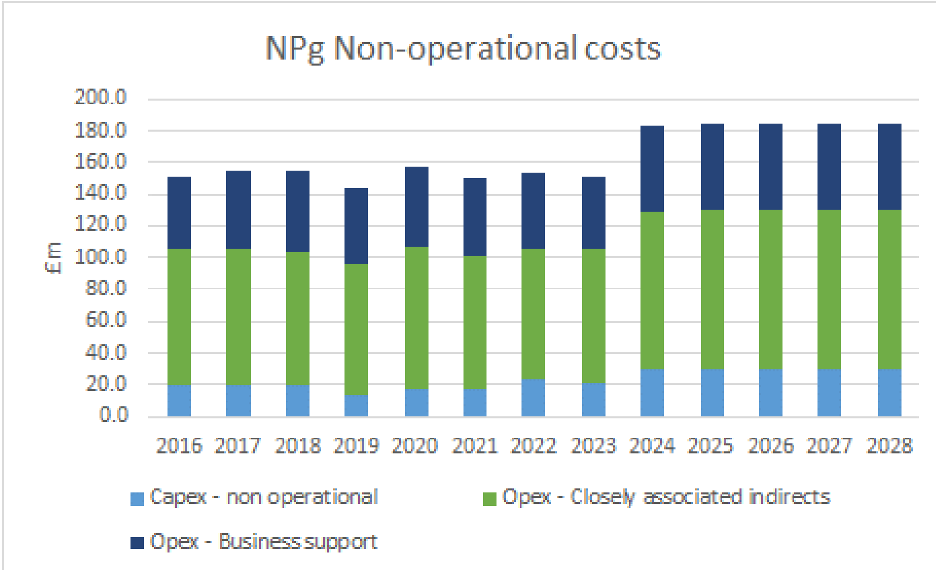
Under this cost grouping we have included business support, closely associated indirects and non-operational capex. The NPg bid is for £269m of business support costs (an increase of 11%), £500m of closely associated indirects (an increase of 18%), and £150m of non-operational capex (an increase of 57%). The combined increase is 21%. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 60: NPg non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 192.8 | 139.8 | 24.1 | 28.0 | 16% |
| IT& Telecoms (Business Support) | 148.3 | 97.3 | 18.5 | 19.5 | 5% |
| Property Mgt | 47.2 | 32.3 | 5.9 | 6.5 | 10% |
| **Total Business Support Costs** | 388.4 | 269.4 | 48.5 | 53.9 | 11% |
| **Closely associated indirects** | | | | | |
| Core CAI | 477.9 | 377.7 | 59.7 | 75.5 | 26% |
| Wayleaves | 80.2 | 48.6 | 10.0 | 9.7 | -3% |
| Operational Training (CAI) | 81.9 | 51.4 | 10.2 | 10.3 | 0% |
| Vehicles and Transport (CAI) | 36.2 | 22.7 | 4.5 | 4.5 | 0% |
| **Total CAI** | 676.2 | 500.4 | 84.5 | 100.1 | 18% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 68.7 | 74.1 | 8.6 | 14.8 | 73% |
| Property (Non-Op) | 16.3 | 13.4 | 2.0 | 2.7 | 32% |
| Vehicles and Transport (Non-Op) | 48.7 | 33.2 | 6.1 | 6.6 | 9% |
| Small Tools and Equipment | 18.8 | 29.1 | 2.3 | 5.8 | 148% |
| **Total non-op capex** | 152.5 | 149.8 | 19.1 | 30.0 | 57% |

A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown, below. The profile shows a sharp increase at the start of the ED2 period and continues thereafter.

*Chart 18: NPg overall non-operational cost profile*




NPg provide evidence to justify these significant increases in their business plan. While details of increases are included, we are concerned that efficiency opportunities have not been sought with corresponding rigour, and these non-operational costs may be overstated as a result.

### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. NPg have proposed a 0.5% annual ongoing efficiency challenge. As shown below, the corresponding forecasts in business plan data tables indicate an overall ED2 saving of 1.5%. NPg are forecasting real price effects over ED2 that total 6.7%.

*Table 61: NPg Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| NPg | 200 | 6.7% | 45 | 1.5% | 2970 |

NPg's RPE forecasts are amongst the highest of the DNOs and we do not consider this level has been justified. Their OE is amongst the lowest. We suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 4.2 (iii) Uncertainty mechanisms

NPg have not proposed any bespoke uncertainty mechanisms but it is anticipated that they will be a participant in a sector-wide load-related capex uncertainty mechanism alongside other common UMs. A figure of £195m or 6% of their totex bid for this uncertainty is included in their business plan submission.

We agree that a LRE uncertainty mechanism is necessary, or it could lead to consumers either bearing the cost of additional LRE expenditure which turns out not to be needed, or providing a windfall gain from underspend. In NPg's case, we suggest that their high forecast non-load capex expenditure is the upper level at which an uncertainty mechanism for ED2 may be required.

## 4.3 DSO and whole system

### 4.3 (i) DSO and digitalisation strategy

In their DSO plan, NPg propose the following key strategies:

- **Flexibility –** deploy flexibility market solutions as an alternative to network reinforcement when economic to do so;
- **Whole system –** enable whole energy system solutions by engaging with the wider market;
- **Data and digitalisation –** deliver open data, digital insight and digital tools;
- **Openness –** gain trust through publishing investment decisions and flexibility needs; and,
- **Skills –** build in-house, regional and national skills.

NPg aim to specify flexibility and data outcomes and to measure their performance against these. They target 138MW of DNO-contracted flexibility capacity during ED2, representing 2% of 2028 peak demand. NPg's targeted benefits are:

- Up to £201m of reinforcement costs will be avoided over the course of 2023-28;
- Better data and analytics will drive more efficiency in network investment;
- Maximising the utilisation of existing infrastructure;
- Rollout of active network management to enable faster connections; and,
- Allow customers to gain revenue from participating in flexibility markets.

NPg's breakdown of DSO costs and benefits from flexibility-based solutions propose that some £90m (including 48 people by 2028) will be invested in DSO activities, including LV monitoring, during ED2 and that this will result in £155m of net savings over this period. The savings are attributed to consumer price driven flexibility (£108m), DNO contracted flexibility (£14m), and savings from smart solutions (£65m).

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table 62: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| NPg | 6,662 | 554 | 138 | 2% | 25% | 155 |

Our view is that the plan represents a steady evolution from ED1 with a greater focus on flexibility, but some of the claimed benefits appear to be from external factors. For example, the business plan shows a reduction in network reinforcement of £108m as a result of price-driven flexibility (understood to be time-of-use tariffs). The savings from DNO contracted flexibility appear unambitious, offering few benefits from interaction with distributed energy resources or other third parties. While there are plans to realise potential benefits through interaction with the ESO, we consider these could have been developed further.

***Digitalisation***

NPg's data and digitalisation strategy proposes £107m of expenditure during ED2, with around half of this being targeted at DSO activities. The digitalisation strategy appeared to have limited ambition. For example, we considered that plans for applications to deliver process redesign or dynamic interactions with stakeholder data could have been further developed.

The DSO digitalisation strategy addresses the key areas, but we are concerned that the enhancements and benefits are inwardly focused and may not allow all benefits to be sought from external market participants. A network-centric vision may block routes to other electricity markets, including community models and may not be appropriately targeted to deliver the benefits from flexibility markets in particular.

### 4.3 (ii) Whole system strategy

NPg have set out the following strategic objectives and outcomes for their whole system plan. The strategic objectives are to:

- Drive whole system decarbonisation;
- Unlock value for customers;
- Create a network for the next generation energy system; and,
- Collaborate with proactive whole system planning.

NPg propose the following key outcomes (and associated costs) as part of their whole system strategy:

- Remove barriers for customers to use their equipment (£1.8m);
- Cross-sector and cross-vector planning e.g., Local Energy Action Plans (£6.2m);
- Rolling out proven innovation e.g., CLASS voltage optimisation (£19m); and,
- Exchange knowledge about LCT product and service design (£0.1m).

Overall, these appear to maintain a largely business-as-usual approach with a relatively low level of ambition. They appear limited to the NPg network and do not demonstrate significant whole system actions external to the NPg electricity system. For example, there is limited extension into heat and transport vectors, nor is there a focus on organisational change to realise whole system outcomes. The proposed outcomes may more readily be described as inputs. Potential benefits are not quantified or targeted.

## 4.4 Other outputs

### 4.4 (i) Environmental Action Plan

NPg's strategic vision is now better articulated in the EAP. We welcome both the emphasis on its leadership role in relation to good environmental practice and achieving Net Zero, and the emphasis on innovation to deliver increased outputs at no extra cost. However, we consider that this is still not an ambitious plan in terms of decarbonisation and does not live up to the leadership vision.

NPg have now had verification of an SBT with a 1.5°C trajectory. They have opted for a 4.2% annual reduction to achieve a 21% reduction in Scope 1 and 2 emissions excluding losses (20% reduction in "controllable internal BCF"). This distinction is not clearly explained. In our view, the 20/21 % target is not ambitious. It is at the lower end of DNO targets. The optioneering around reducing building and substation energy use does not seem to have considered higher levels of energy efficiency measures in place of renewable generation.

In response to stakeholder challenge, they have also set a target for reduction in scope 3 emissions (20%), although this is not consistently shown as a deliverable, with the emphasis still on reporting on scope 3 emissions. In any event, our view is that this is not ambitious in comparison with other DNOs and the targets for percentage of supplier base adopted by others suggest that this should be readily achievable so we hope that they will revisit during ED2.

NPg have been responsive to stakeholders in focusing on carbon reduction rather than offsetting but it is not clear whether there are plans for carbon abatement as part of biodiversity initiatives. This is something which other DNOs have made significantly more progress on.

The fleet electrification target is not ambitious but does appear to be reflective of consumer feedback – essentially it is in line with fleet replacement. However, NPg are the only DNO to refer to ULEVs as well as EVs. We were pleased to note the proposal to investigate shared charging with other regional utilities.

NPg have been a strong performer, historically, on $SF_6$. Its $SF_6$ strategy seems to include what we would expect in terms of management and exploring options for $SF_6$-free assets where this would be cost effective. However, the different performance between the two regions is not explained – whilst this may be due to network characteristics or infrared camera deployment, we would have found it helpful for the issues to be clarified in response to our challenge on their draft plan. There is useful detail about steps being taken to identify leaks and manage and indeed reduce leakage in the EAP but this seems to be a substitute for a more detailed $SF_6$ strategy.

The losses strategy, which is summarised in the EAP, includes asset replacement, steps to reduce energy use and therefore to mitigate losses through active voltage management, investigation of technological solutions and innovation.

### 4.4 (ii) Vulnerability strategy

This is a straightforward strategy which, if delivered, would represent a significant step up in activity for NPg with a commensurately material increase in costs.

In some areas of activity, it is clearly catching up with most other DNOs. For example, it plans to build a 'data and information strategy' in ED2, which will be essential to deliver effectively. However, most other DNOs have already worked on this to a fairly sophisticated level in ED1.

This strategy clarifies that it is aiming to register 50% of all eligible PSR customers by the end of ED2, with a higher target of 70% for 'high risk' eligible customers. It is appropriate to prioritise its efforts in this way, but the 50% target would nevertheless still appear to leave NPg behind other DNOs in terms of overall PSR registrations by the end of the period. If the NPg target remains significantly adrift of the other companies, once the ongoing work to make metrics comparable across the DNOs is complete, this would be of increased concern (and we would probably have awarded a lower comparative rating for this strategy). We would encourage NPg to accelerate its work in this area now so that it can operate from a more effective starting point in 2023.

The strategy sets out a range of practical and welcome new commitments in terms of contact and support in the event of a power cut. For example, it talks about contacting all high-risk customers within one hour in the case of an unplanned power cut and all PSR customers within the first three hours. It caveats that it will 'endeavour' to meet these targets, and that it will 'attempt to' speak to PSR customers in advance of planned outages to determine their needs. A delivery plan based on real-world trials and tests would have given more confidence that these commitments can be delivered in practice. It also plans to offer enhanced on-site welfare support when unplanned power cuts exceed 6 hours.

The planned step up in NPg's activity is also marked in the area of fuel poverty. It commits to 'target' 20k households a year with support compared with 4.4k a year now, and 'unlock' £40m of benefits. The fact that this activity is an extension of an existing approach – from two of the company's operating regions to all six – and with established partners, gives us some confidence that this level of commitment can be delivered in practice.

In terms of customer support with the energy transition, NPg say it will 'directly support' 5k customers a year. However, as with ENWL, they seem to be only at an early stage of thinking about how they can best do this. They acknowledge this by saying they will focus on 'understanding emerging issues and impacts', trial approaches using the Network Innovation Allowance (NIA) and review their approach annually.

We welcome the fact that NPg have set out their costs to deliver this strategy more clearly than most others in the body of the strategy. However, in line with the step up in scale of activity, the costs are also materially more – £19.5m in ED2, compared with c.£4m in ED1.

NPg have also proposed a related CVP related, which includes a 'one stop' app for vulnerable customers. This is discussed in NPg's CVP section.

### 4.4 (iii) Reliability

NPg are one of the DNOs with the worst reliability performance in ED1 but they have included c.£60m in their baseline funding to target meaningful improvements for ED2, which they say are the first part of a '10-year plan to deliver a modernised reliable network'. In particular, they are aiming to cut the total time that customers spend without power by about 20%, which would bring them closer to the average network performance. In part, this will be achieved by reducing 'by 50%' the number of customers each year who experience a power cut of more than 12 hours. This is clearly welcome but would still leave 2,700 customers a year experiencing these extremely long periods without power. They also aim to reduce the number of customers experiencing power cuts of over 6 hours by 15%. Again, this would still leave c.74k customers experiencing lengthy power cuts by the end of the price control period. NPg also aim to improve the reliability performance for c.2,800 'worst-served' customers by reducing the total length of power cuts they experience by 25%. Although NPg's plans would improve the service received by all customers categorised as 'worst-served', we were unclear from the plan whether the scale of the improvement planned would be enough to remove customers altogether from this classification.

*Table 63: NPg's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with NPg's performance in ED1.*

| | ED2 Average | | | | % change from ED1 Average | | | |
|---|---|---|---|---|---|---|---|---|
| | CI | CML | CI | CML | CI | CML | CI | CML |
| | (incl. exceptional) | | (excl. exceptional) | | (incl. exceptional) | | (excl. exceptional) | |
| NPgN | n/a | n/a | 42 | 30 | n/a | n/a | -13% | -21% |
| NPgY | n/a | n/a | 46 | 31 | n/a | n/a | -7% | -16% |

## 4.5. Consumer Value Propositions

*CVP1: One stop app for vulnerable customers – not recommended*

NPg are proposing a 'one-stop' app for vulnerable customers to keep their data up to date and access information and direct support from their network of partners. They say the cost would be £1.9m with a 'net consumer value' of £3.3m.

NPg say that this is unique because no other DNO delivers this type of service through an app, and no apps like this in other sectors are targeted specifically at vulnerable customers. We were unconvinced that this amounted to an initiative that was clearly going beyond business as usual among DNOs. As a result, we do not believe it meets the criteria for a CVP award.

The app may have potential as a way to deliver their other commitments – as the Utilita experience that it highlights suggests. But, if it goes ahead, they will also have to overcome significant challenges to drive sufficient awareness, understanding and ongoing usage for it to be effective in practice. NPg address some of this risk with their clawback proposals, with 70% of the award subject to clawback if the forecast 'uptake' does not materialise. It was not clear to us what 'uptake' implied but if Ofgem does accept this as a CVP, we think it should ensure that the clawback is triggered by more specific measures, such as lack of usage or effective referrals rather than just fewer downloads. In other words, it should demonstrate that it is driving outcomes and value in practice.

*CVP2: Open Insights Self-Service Analytics Toolkit – not recommended*

NPg propose the provision of a free online platform (Open Insights) which will provide users with a range of tools that will enable give them access to energy data, undertake network planning and enable to Low Carbon Technologies to be connected. This platform will cost around £6.7m in ED2, delivering an estimated NPV of £4.7m.

The Challenge Group welcomes proposals which give users and customers more access to energy data and the tools with which to use this data. We recognise that access to this data is essential to the development of flexible markets and new services and, as such, should be considered as business as usual for the DSO. We believe that a CVP is not the most appropriate funding mechanism for this proposal and that it could form part of the baseline expenditure and delivery targets for the DSO.

*CVP3: Dynamic Voltage Optimisation – not recommended*

This CVP seeks to roll out voltage optimisation technology to around 165 primary substations serving around 1.2 million customers over ED2, building on the Boston Spa energy efficiency trials (BEET), at a cost of £7.9m. The claimed energy savings of up to £20 per household and carbon savings of 27kg per year are significant and we welcome that these savings would be targeted at fuel-poor customers. But, similar to the ENWL Smart Street project, the savings may be uncertain and impacted by customer demand and distributed LCT characteristics changes.

This proposal builds on a trial of a new voltage optimisation technique in Boston Spa. We believe that this technology is still in the ‘development’ phase and that the claimed benefits are not yet proven. As such, we consider it would be more appropriate to consider funding of this through an innovation scheme, or baseline expenditure, rather than through a CVP.

*CVP4: Next-Generation Energy System – not recommended*

This proposal is for the first stage deployment of a blueprint for a next-generation energy system, which will enhance system resilience for remote and rural customers who are more susceptible to supply interruptions. We note that the cost of this is £6.3m over ED2 and delivers a NPV of £7.6m.

We welcome the development of new initiatives that improve the resilience of supply to customers and help them to participate in the decarbonisation of energy systems. Given the recent experience of NPg and other DNO customers during storm Arwen, such initiatives might be more appropriately required under business as usual rather than gaining additional reward. We understand that this technology is still in the ‘development’ phase and that the claimed benefits are not yet proven. As such, it would be more appropriate to consider funding of this proposal as a baseline activity or through an innovation scheme, rather than through a CVP.

## 4.6 Finance

We commented that NPg’s draft plan did not contain a clear statement of its financeability on the basis of Ofgem’s W/As. The position has been clarified in the BP with an unambiguous statement that the company does not regard its plan as financeable on that basis. We note that NPg have also elected to disregard our comments in relation to their proposed shortening of the depreciation period and continue to advocate a major reduction.

NPg say that they are targeting an A3/A- rating although they have assessed themself ‘against a Baa1/BBB+ rating for the purposes of the BP’. We are uncertain as to the implications of the reference to ‘assessment against’ a given rating but accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status. However, we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. We regard Baa1/BBB+ as at the upper end of the acceptable target range and A3/A- as unnecessary. Certainly, we do not consider that a company needs to demonstrate an expectation of even Baa1/BBB+ to be considered financeable.

NPg reject some of Ofgem’s W/As (sometimes, in our view, in unhelpfully strident terms). They have, however, presented clear analysis for both the Notional and the Actual Company and for both licensees on the basis of those W/As. The results of Ofgem’s required stress tests are also clearly and well presented. NPg’s analysis shows that, in the Notional Company base case, Northeast is at the low end of investment grade at Baa3 and Yorkshire just below investment grade at Ba1. The stress testing confirms these results. The results for the Actual Company show a clear A3 rating across both licensees in the base case with Northeast retaining that rating and Yorkshire a satisfactory Baa1 even in the downside RoRE case, all based principally on a lower gearing assumption (55% for Northeast and 57% for Yorkshire). Changes to the gearing assumption are one of Ofgem's proposed aids to financeability for the Notional Company and we are not clear why NPg have chosen to focus principally on an increase in the cost of equity assumption. It is our view that a reduction in gearing along the lines assumed proposed for the Actual Company projections, with or without a minor change to the depreciation period and/or some dividend restraint, would make both Notional Companies financeable on the basis of Ofgem's cost of capital W/As (although there are no results presented which would directly support that contention).

NPg propose that the allowed cost of equity should be 'above 5.8%'. We do not consider this to be in the best interests of their consumers. As set out above, the analysis shows that the Actual Company (with gearing at an average 56%) is financeable with a clear A3 rating and that there are mitigating measures which would be likely to make the Notional Company financeable too, even if not at Baa1/BBB+, and based on an effective cost of equity allowance of 4.65%. We would expect to see mitigating measures much more fully explored before there is any suggestion of an allowed rate in excess of 4.4% (i.e. with no outperformance).

We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions. NPg make a number of criticisms of Ofgem's methodology and assumptions, including commentary about comparisons with other sectors which we address there.

All of NPg's analysis has been based on 60% gearing, a depreciation period of 45 years, and an average capitalisation rate across the two licensees of 71%, which the company says is set to reflect the rate used in ED1 but which is also near to its natural rate. NPg advance forceful arguments for a very much shorter depreciation period than Ofgem's W/A of 45 years. We made clear in our commentary on its draft plan that we considered a shift of the magnitude proposed to be excessive, but we see no reason why a small adjustment to the depreciation period could not form a helpful component of a suite of measures to aid financeability. NPg base their projections for the Actual Company on gearing below the 60% proposed in the SSMD for the Notional Company; in our view lower gearing, whether or not exactly in line with that which NPg assume for the Actual Company, could make a further substantial contribution to financeability of the Notional Company. Finally, NPg refer to having 'a shareholder with a track record of reinvesting heavily in our business'. We believe that NPg should – and could have – examined the impact of new equity (or dividend restraint) in order to ensure that it is financeable on the basis of a Notional and an Actual capital structure.

NPg's Business Plan Commitment and Assurance Section contains an explicit statement that their licensees 'would not meet Ofgem's financeability criteria on a notional capital structure basis (using Ofgem's working assumptions for cost of capital allowances and expected outperformance)' (i.e. an effective cost of equity allowance of 4.65%).

There is no assurance statement, positive or negative, in the 'Business Plan Commitment and Assurance Section' of the BP in relation to the Actual Company. We consider this omission unhelpful especially since, as indicated above, we consider the Actual Company clearly financeable on the basis of Ofgem's W/As and the Notional Company highly likely to be so also, with the application of appropriate mitigating measures.

# 5. Company report – SPEN

As a summary, we have assigned SPEN's Business Plan the following ratings:

*Table 64: SPEN BP scores[15]*

| | |
|---|---|
| Track record from RIIO-ED1 | 2 |
| Scenarios and forecasts | 4 |
| Totex: LRE, incl. anticipatory investment | 4 |
| Totex: NLRE, incl. asset health | 2 |
| Totex: Network operating costs | 3 |
| Totex: Non-operational costs | 3 |
| Totex: Ongoing efficiency and RPE | 1 |
| Totex: Uncertainty mechanisms | 2 |
| Outputs: DSO and digitalisation strategy | 3 |
| Outputs: Whole system strategy | 2 |
| Outputs: EAP | 4 |
| Outputs: Vulnerability strategy | 4 |
| Outputs: Reliability | 3 |
| Finance | 3 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of SPEN's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 94% from ED1 levels and we are concerned that this may not include benefits from network capacity optimisation.
- **DSO and whole system –** SPEN are targeting annual flexibility actions of 550MW, delivering benefits of £370m over ED2. We are concerned that these benefits may not be realised and that they are not reflected in load-related capex forecasts. SPEN's DSO costs appear high and may not offer value for money.
- **Costs –** Baseline totex is similar to the draft plan and is forecast to increase by 26% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that underlying cost increases for the same asset basis are unjustified.
- **Risks and uncertainty –** SPEN have proposed uncertainty mechanisms which could add £243m or 7% of totex (and potentially more). We are concerned that some of these costs may already be included in baseline expenditure.
- **Finance –** In our view, SPEN's modelling provides a clear demonstration of the financeability of their BP on the basis of Ofgem's Working Assumptions (W/As) for the cost of capital. We would like to understand why the plan contains contradictory statements about financeability and whether the statement that it is financeable is to be relied on. We would also like to understand why SPEN have not shown the results of a full exploration of Ofgem's 'levers' for improving financeability which would be likely in our

[15] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

view to enable them to finance their plan with a cost of equity allowance below 4.65% (to the benefit of SPEN's customers).

## 5.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

The key performance measures are shown in the tables below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 65: SPEN ED1 performance summary*

| **ED1 performance (2021 RRP)** | **SPEN** |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 0.7% |
| Customer service (BMCS) | 0.5% |
| Time to connect (TTC) | 0.1% |
| **Output incentives total** | 1.2% |
| | |
| **Totex efficiency incentives** | (0.8%) |
| **Operational RoRE** | 6.1% |

**ED1 - Totex (2021 PCFM)**

| **£m (2012/13 prices)** | **SPEN** |
|---|---|
| Totex allowance | 3229 |
| Totex actual/forecast | 3319 |
| % totex (under)/overspend | 3% |
| % LRE (under)/over spend | (12%) |
| % Totex (excl. LRE) (under)/overspend | 4% |

Overall, we note that SPEN expect their ED1 totex outturn to exceed their allowance by 3%. They are showing an underspend of 12% in load-related capex, largely attributable to lower-than-expected LCT growth. Once load-related capex is excluded, overall outturn totex expenditure is expected to be 4% higher than the allowance.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) reward is amongst the lowest of all DNOs and the customer service incentive (BMCS) is amongst the highest.

## 5.2 Costs, scenarios and forecasts

### 5.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios that SPEN has examined and that these scenarios appear to be consistent with Net Zero targets. By the end of ED2, SPEN forecast they will have connected:

- 674k EVs and 366k heat pumps under their Best View (Baseline) scenario; and,
- 1027k EVs and 808k heat pumps under their Upper View scenario.

These scenarios are presented below as 'Best View' and 'Upper View'.

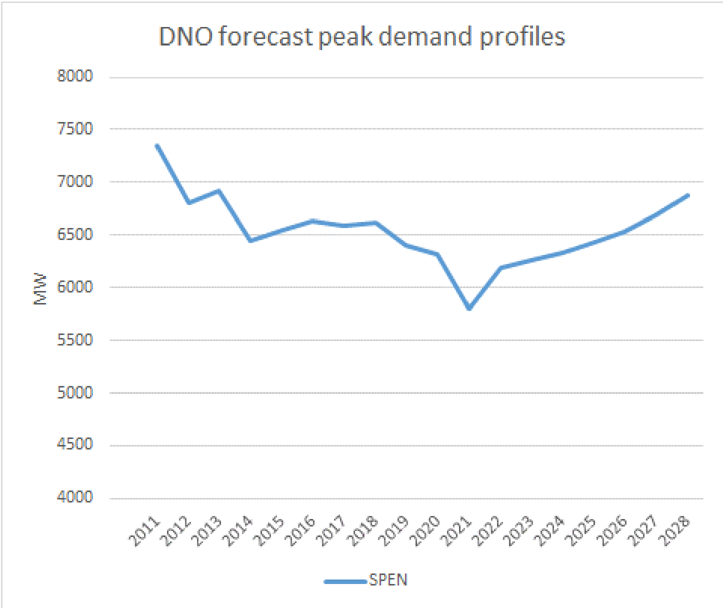
*Table 66: SPEN low-carbon technology scenarios*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| SPEN | 674 | 19% | 366 | 10% | 1027 | 29% | 808 | 23% |

SPEN have around 12% of the networks' total customer base. The forecast number of EVs and heat pumps in the Planning scenario across this customer base in 2028 is broadly in line with the ESO FES Consumer Transformation or Leading The Way scenarios, which forecast around 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers.

The SPEN submission of demand profiles in the BPDTs (shown below) shows an increase of around 9% between 2020 and 2028, which is broadly consistent with the equivalent peak demand increase of 11% forecast in the ESO 2021 'Consumer Transformation' scenario and the 7% growth forecast in the ESO System Transformation scenario.

*Chart 19: SPEN forecast peak demand profile*




Overall, we consider that SPEN have undertaken effective scenario planning, taking account of upward and downward demand drivers, and providing scenario assumptions that are consistent with relevant national forecasts.

### 5.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered.

- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages.

The SPEN ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £3,270m and is a 26% increase on the annual average expenditure rate during ED1. This forecast has increased marginally from the forecast £3,231m figure submitted in their draft plan. The following table compares the SPEN cost submissions between 8-year ED1 actuals/forecasts and 5-year ED2 forecasts. It also compares the draft and final plans.[16]

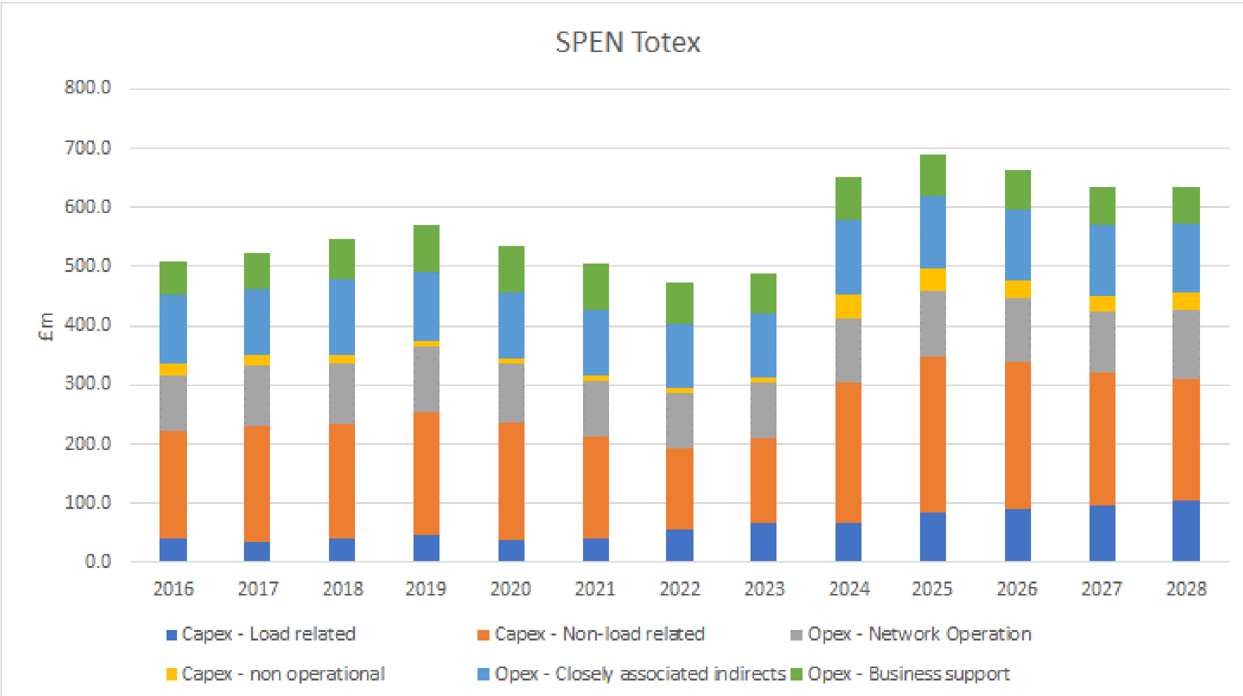
*Table 67: SPEN overall totex comparison*

| SPEN | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| Overall | ED1 | ED2 | ED1 | ED2 | ED1-ED2 | ED1 | ED2 | ED1 | ED2 | ED1-ED2 |
| Capex - Load related | 366.9 | 444.5 | 45.9 | 88.9 | 94% | 329.9 | 430.3 | 41.2 | 86.1 | 109% |
| Capex - Non-load related | 1427.2 | 1177.9 | 178.4 | 235.6 | 32% | 1406.4 | 1199.7 | 175.8 | 239.9 | 36% |
| Opex - Network Operation | 788.1 | 545.7 | 98.5 | 109.1 | 11% | 792.5 | 509.2 | 99.1 | 101.8 | 3% |
| Capex - non operational | 98.4 | 164.3 | 12.3 | 32.9 | 167% | 105.8 | 122.7 | 13.2 | 24.5 | 86% |
| Opex - Closely associated indirects | 910.1 | 606.6 | 113.8 | 121.3 | 7% | 896.4 | 608.4 | 112.1 | 121.7 | 9% |
| Opex - Business support | 557.7 | 331.4 | 69.7 | 66.3 | -5% | 542.0 | 360.3 | 67.8 | 72.1 | 6% |
| **BPDT Totex** | 4148.4 | 3270.4 | 518.6 | 654.1 | 26% | 4073.1 | 3230.6 | 509.1 | 646.1 | 27% |
| **Baseline totex after OE/RPE adjustments** | | | 518.6 | 701.4 | 35% | | | | | |
| **Baseline totex with UMs (excl. Access SCR)** | | | 518.6 | 750.0 | 45% | | | | | |

A profile of the totex and main expenditure categories is shown in the chart, showing a significant increase at the start of ED2, especially in non-load capex.

[16] Note: These totex figures exclude 'other costs outside the price control'. The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.

*Chart 20: SPEN overall totex profile*




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for underlying expenditure on a similar asset base, and we have scrutinised reasons for increases from these levels. Our assessments for these individual cost categories are set out below, seeking to understand the justifications for these potential increases.

### *ii.a. Totex: LRE*

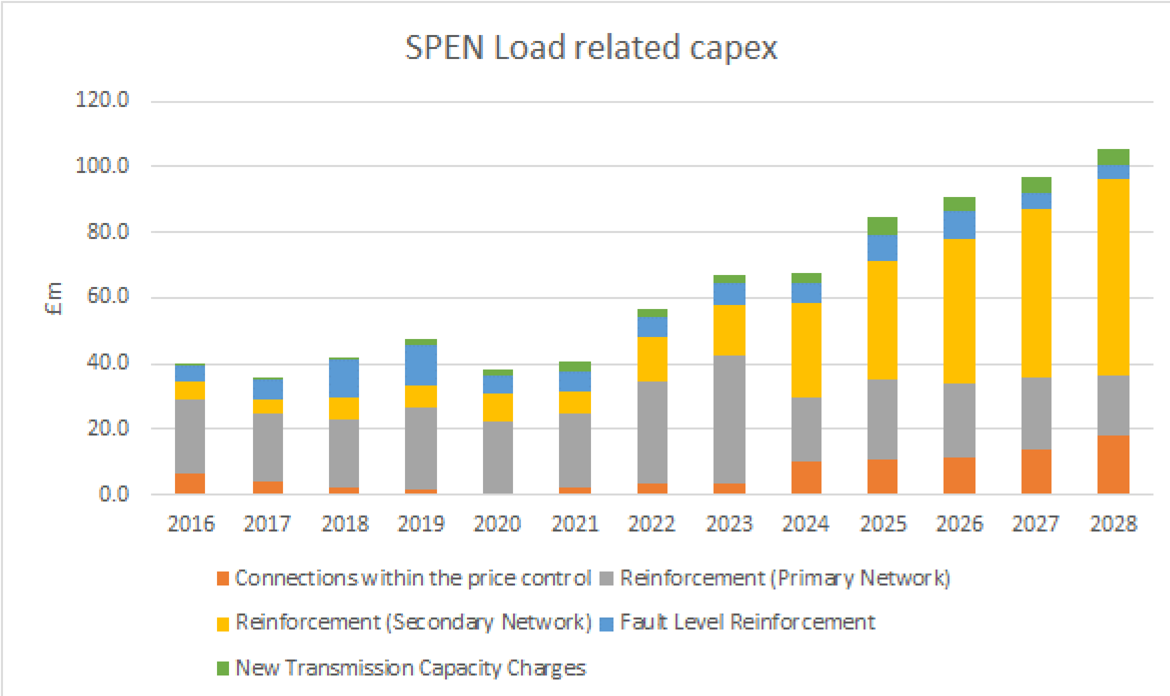
The SPEN bid for baseline LRE is £444m, which represents a 94% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual categories, with reinforcement relating to secondary networks and connections showing significant increases.

*Table 68: SPEN load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Connections within the price control | 24.3 | 63.6 | 3.0 | 12.7 | 320% |
| Reinforcement (Primary Network) | 203.3 | 107.0 | 25.4 | 21.4 | -16% |
| Reinforcement (Secondary Network) | 66.4 | 220.6 | 8.3 | 44.1 | 431% |
| Fault Level Reinforcement | 60.0 | 31.1 | 7.5 | 6.2 | -17% |
| New Transmission Capacity Charges | 12.8 | 22.2 | 1.6 | 4.4 | 177% |
| **Total load related costs** | 366.9 | 444.5 | 45.9 | 88.9 | 94% |

A profile of the LRE expenditure categories is shown, below. It shows a significant increase over the course of ED2, especially in secondary network reinforcement.

*Chart 21: SPEN load-related capex profile*




We consider that SPEN have provided reasonable justifications for increases in LRE, especially relating to the need to address anticipated LV network capacity constraints to connect low-carbon technologies. We noted that SPEN's plan had considered the availability of current capacity headroom, and proposed to increase network utilisation, including through benefits from flexibility and smart control. However, we are concerned that this ambition is not reflected in the proposed baseline bid which may therefore be overstated – a further proportion of this may be best addressed through uncertainty mechanisms.

We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

***ii.b. Totex: NLRE***

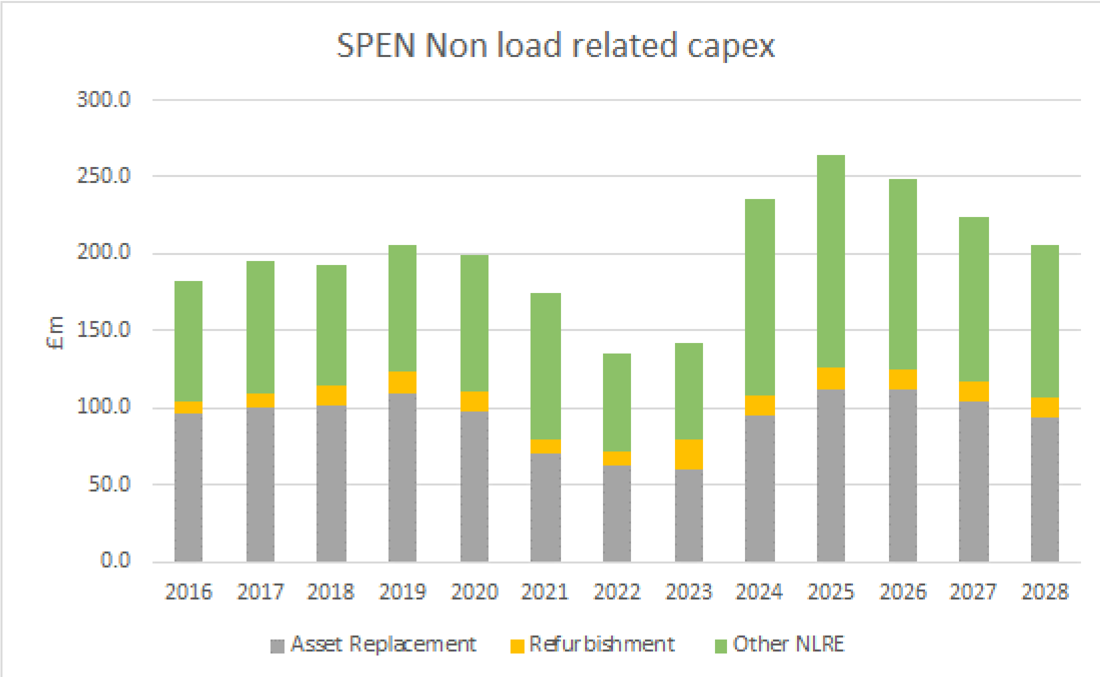
The SPEN bid for baseline NLRE is £1,178m, which represents a 32% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories. Reinforcement relating to asset replacement/refurbishment, and operational IT and telecoms are particular areas showing significant increases.

*Table 69: SPEN non-load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Non Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Diversions (Excluding Rail Electrification) | 62.2 | 57.0 | 7.8 | 11.4 | 47% |
| Diversions Rail Elec | 0.0 | 0.0 | 0.0 | 0.0 | |
| Asset Replacement | 700.3 | 518.2 | 87.5 | 103.6 | 18% |
| Refurbishment | 94.1 | 65.8 | 11.8 | 13.2 | 12% |
| Civil Works Condition Driven | 86.6 | 38.1 | 10.8 | 7.6 | -30% |
| Operational IT and telecoms | 84.0 | 221.4 | 10.5 | 44.3 | 322% |
| Blackstart | 4.5 | 6.5 | 0.6 | 1.3 | 133% |
| BT21CN | 25.1 | 0.0 | 3.1 | 0.0 | -100% |
| Legal & Safety | 42.1 | 40.7 | 5.3 | 8.1 | 55% |
| QoS & North of Scotland Resilience | 25.8 | 26.4 | 3.2 | 5.3 | 64% |
| Flood Mitigation | 1.6 | 9.6 | 0.2 | 1.9 | 863% |
| Physical Security | 0.0 | 0.0 | 0.0 | 0.0 | |
| Rising and Lateral Mains | 100.4 | 61.1 | 12.6 | 12.2 | -3% |
| Overhead Line Clearances | 166.4 | 24.8 | 20.8 | 5.0 | -76% |
| Worst Served Customers | 0.2 | 14.6 | 0.0 | 2.9 | |
| Environmental Reporting & Losses | 34.0 | 93.7 | 4.2 | 18.7 | 341% |
| HVP | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Total non load related capex** | 1427.2 | 1177.9 | 178.4 | 235.6 | 32% |

A profile of the NLRE expenditure categories from 2016 to 2028 is shown, below. It shows a significant decline at the end of ED1 before increasing at the start of ED2. While we note that SPEN is on track to deliver asset health targets for ED1, we are concerned that the ED2 increase may be due to high-cost asset replacement expenditure being deferred to ED2. This risks customers having to pay twice for the same replacement work.

*Chart 22: SPEN overall non-load capex profile*




We recognise that there are some upward cost drivers in relation to DSO and network visibility investment, and from accelerated PCB removal. However, we do not think the scale of NLRE expenditure increases for ED2, especially for asset replacement have been justified given the underlying asset base remains largely similar to that for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We note that SPEN are targeting a network risk target of 27.1%, resulting in a closing ED2 position of 5.7% above opening. The forecast monetised risk reduction is 43.7 pence per point. The closing network risk target of 5.7% is slightly higher than may be expected.

For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The SPEN profile is shown below:

*Table 70: Low Voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| SPD | 1942 | 524 | 759 | -73% | 45% |
| SPM | 3317 | 1004 | 1673 | -70% | 67% |
| TOTAL | 5259 | 1527 | 2432 | -71% | 59% |

The forecast number of LV poles subject to asset replacement during ED2 is significantly greater than ED1, and we have examined the EJP in more detail.

The EJP states that this investment is needed in the overhead network to ensure current network performance and customer safety standards can be met. We acknowledge that the age of wood poles is increasing and an increase in the rate of replacement may be required. We ask Ofgem to carefully examine this increased pole replacement programme, alongside other asset replacement strategies, to ensure that it delivers value for money for consumers.

We welcome that, in the constrained parts of the network, the opportunity will be taken to increase the capacity of the circuits when a conductor is replaced. We would like this increase capacity to be quantified and, where appropriate, reflected in the forecasts for LRE.

### *ii.c. Totex: Network operating costs*

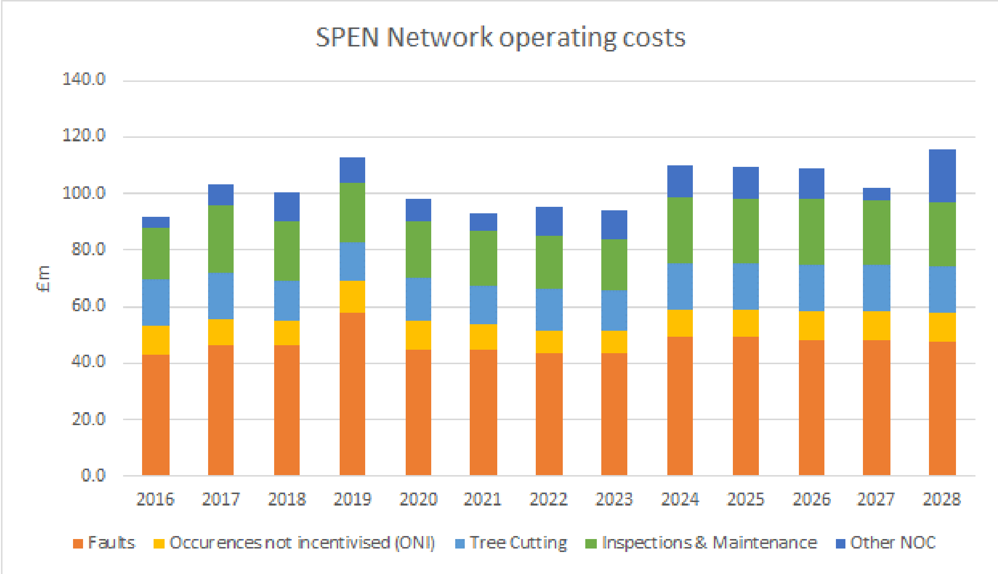
The SPEN bid for network operating costs is £546m, which represents an 11% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with the most significant increases being in Inspections & Maintenance and Tree Cutting. Smart meter costs have decreased slightly but not by as much as forecast by other companies.

*Table 71: SPEN network operating cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Opex - Network Operating Costs** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Faults | 369.2 | 241.6 | 46.2 | 48.3 | 5% |
| Severe Weather 1 in 20 | 0.0 | 14.4 | 0.0 | 2.9 | |
| ONIs | 75.5 | 50.5 | 9.4 | 10.1 | 7% |
| Tree Cutting | 118.5 | 82.0 | 14.8 | 16.4 | 11% |
| I&M | 159.6 | 114.3 | 19.9 | 22.9 | 15% |
| NOCs Other | 31.8 | 22.6 | 4.0 | 4.5 | 14% |
| Smart Meters | 33.5 | 20.2 | 4.2 | 4.0 | -4% |
| **Total Network Operating Costs** | 788.1 | 545.7 | 98.5 | 109.1 | 11% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown below. The profile increases over the first two years of the ED2 period.

*Chart 23: SPEN overall network operating cost profile*




Overall, while we have considered the evidence provided by SPEN, we do not consider that justifications have been provided for these increases. These costs may be higher than necessary given that other DNOs have been able to deliver cost reductions in this area.

### *ii.d. Totex: Non-operational costs*

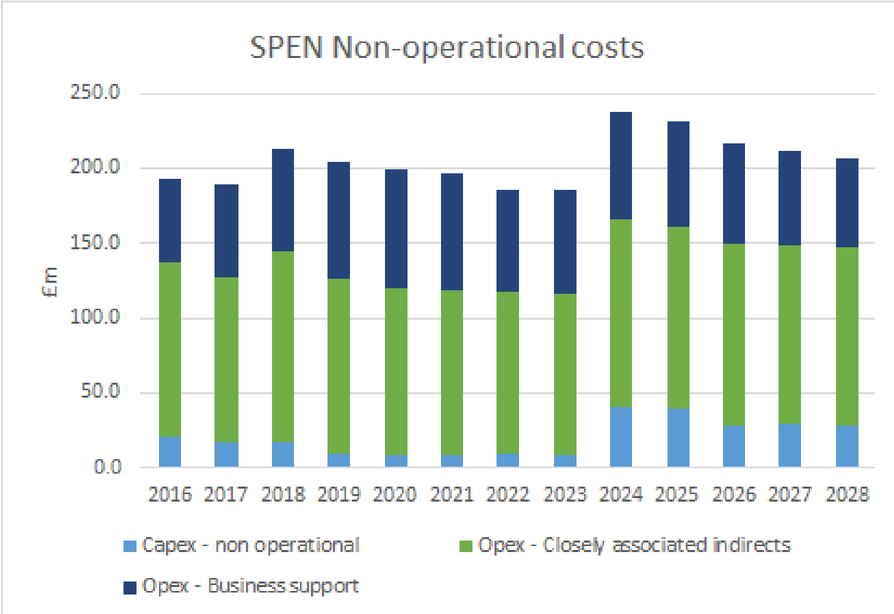
Under this cost grouping we have included business support, closely associated indirects and non-operational capex. The SPEN bid is for £331m of business support costs (a decrease of 5%), £607m of closely associated indirects (an increase of 7%), and £164m of non-operational capex (an increase of 167%). The combined increase is 13%. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 72: SPEN non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 293.0 | 158.9 | 36.6 | 31.8 | -13% |
| IT& Telecoms (Business Support) | 176.6 | 122.3 | 22.1 | 24.5 | 11% |
| Property Mgt | 88.1 | 50.2 | 11.0 | 10.0 | -9% |
| **Total Business Support Costs** | 557.7 | 331.4 | 69.7 | 66.3 | -5% |
| **Closely associated indirects** | | | | | |
| Core CAI | 674.7 | 386.0 | 84.3 | 77.2 | -8% |
| Wayleaves | 50.4 | 61.1 | 6.3 | 12.2 | 94% |
| Operational Training (CAI) | 99.2 | 89.1 | 12.4 | 17.8 | 44% |
| Vehicles and Transport (CAI) | 85.8 | 70.4 | 10.7 | 14.1 | 31% |
| **Total CAI** | 910.1 | 606.6 | 113.8 | 121.3 | 7% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 57.6 | 99.3 | 7.2 | 19.9 | 176% |
| Property (Non-Op) | 26.8 | 41.2 | 3.3 | 8.2 | 146% |
| Vehicles and Transport (Non-Op) | 2.1 | 12.4 | 0.3 | 2.5 | 826% |
| Small Tools and Equipment | 11.9 | 11.5 | 1.5 | 2.3 | 54% |
| **Total non-op capex** | 98.4 | 164.3 | 12.3 | 32.9 | 167% |

A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown, below. The profile shows a sharp increase at the start of the ED2 period and declines thereafter.

*Chart 24: SPEN overall non-operational cost profile*




The major increase is in non-operational capex, including IT/telecoms and property. We note that SPEN have sought significantly higher DSO cost increases than other companies and this may contribute in part to these increased costs. We are concerned that efficiency opportunities have not been sought with corresponding rigour, and these non-operational costs may be overstated as a result.

### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. SPEN have proposed a 0.5% ongoing efficiency challenge. As shown, below, the corresponding forecasts in business plan data tables indicate an overall ED2 saving of 1.5%. SPEN are forecasting real price effects over ED2 that total 8.3%.

*Table 73: SPEN Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| SPEN | 270 | 8.3% | 48 | 1.5% | 3270 |

SPEN's RPE forecasts are the highest of the DNOs and we consider that this increase has not been justified. We also note that the OE challenge amongst the lowest. We suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 5.2 (iii) Uncertainty mechanisms

SPEN have proposed several bespoke uncertainty mechanisms, as detailed below. Cost estimates for the first two items are taken from business plan data tables and total £243m or 7% of their totex bid.

*Table 74: SPEN UMs*

| Category | Risk addressed | Potential cost |
|---|---|---|
| Load-related expenditure, including LCT unlooping/fuses | Uncertain load-related investment | £213m |
| Load-related - operational IT/telecoms | Uncertain expenditure | £30m |
| Electricity system restoration | Uncertain expenditure | £6.5m included in plan, |
| Other IT | Uncertain expenditure | £20m included in plan |
| Environmental legislation, incl. PCBs | Uncertain expenditure | £56m in data tables |
| Smart meters | Uncertain expenditure | £20m included in plan |

However, in the time available, we have not been able to fully reconcile the potential uncertainty costs with other information provided in company plans. As such we have commented on the principles relating to these risks and mechanisms rather than the costs proposed. We agree that it would be appropriate to include LRE uncertainty mechanisms but would like to see that these are appropriately calibrated in terms of costs, volumes and triggers, and that Ofgem ensures that investment is delivered and does not provide windfall gains for companies.

For the remaining risks, we consider that these should be risks best managed by SPEN who would be best placed to limit both impact and cost. Our concern is that these risks may already be adequately funded by the baseline expenditure forecasts and these potential additional cost drivers will only serve to benefit companies.

However, if Ofgem determines that these risks should be included as uncertainty mechanisms, we suggest this should only take place if reasonable expenditure and contingency allowances are not already included in baseline. If applied, the triggers and volume drivers would also need to be appropriately calibrated.

## 5.3 DSO and whole system

### 5.3 (i) DSO and digitalisation strategy

SPEN are proposing to spend £186m on DSO activities in ED2 (an increase compared to the draft plan forecast of £151m) and are targeting 52% of secondary substations to have metering installed. SPEN's business plan data submission for DSO costs identifies a complement of 188 staff by 2028. SPEN are proposing that 550MW of demand (or 8% of 2028 peak demand) will be met through flexibility services.

SPEN's plan proposes the following initiatives:

- **Planning & network development –** including: further develop forecasting tools and produce annual reports; installation of 14,102 LV network monitors; enhancement of network modelling and monitoring; the introduction of effective processes for sharing planning information; the publication of evidence on decision making; and, establishing a robust optioneering process.
- **Network operation –** including: network monitoring, forecasting platform development, work through ENA to co-ordinate DER providing flexibility, plus exchange of data with the ESO. It plans to roll out decision making framework and near-time forecasting platform, and will test secondary trading arrangements.
- **Market development –** including: flexibility portal to be developed and data accessibility to be developed; a report on conflicts of interest; publishing relevant data to enable market participation; and, developing a clear process for securing flexibility resources from third parties.
- SPEN also plan to establish a new DSO directorate and functional model, including a stakeholder panel and transparent decision making.

The SPEN assessment of DSO benefits identifies the following:

- £9m from flexibility services for high utilisation groups – £9m over 45 years;
- LV network monitoring – £32m over 25 years;
- DSO infrastructure – £328m over 45 years; and,
- Unquantified indirect economic, social, and environmental benefits.

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table 75: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| SPEN | 6,871 | 558 | 550 | 8% | 99% | 370 |

The benefits of £370m identified above are because of SPEN's entire long-term DSO strategy, not just from flexibility actions during ED2.

The SPEN DSO expenditure shows a significant increase from ED1 levels and presents the highest DSO cost/MW across DNOs. However, this may well be due to SPEN adopting a different allocation of costs and staff and we would suggest that Ofgem investigates this further. Overall, while there is some good evolving thinking and the plan has progressed, we consider the flexibility benefits during ED2 appear low overall and we are concerned that the delivery of these benefits during ED2 may not be realised.

***Digitalisation***

The SPEN plan for ED2 identifies a number of digitalisation initiatives for ED2, building on their Network Asset Management System introduced in ED1. They propose to use digitalisation to unlock significant consumer benefits and efficiencies. Initiatives are proposed in the areas of capital projects, asset management, field operations, DSO, and customer/stakeholder engagement.

Overall, we consider the SPEN digitalisation strategy includes welcome ambition and plans for improvement over ED2, addressing network monitoring and process optimisation. However, delivery is set out at a high level and the delivery and achievement of customer benefits may be uncertain.

#### 5.3 (ii) Whole system strategy

SPEN propose a whole system strategy will be delivered through the adoption of a coordinated and collaborative approach across their business. This will be embedded into their organisation through:

- Structured strategic engagement beyond the electricity sector;
- A whole system planning function which will deliver a NPV benefit of £8-49m over ED2; and,
- A business transformation initiative, including the introduction of a new target operating model.

The aim of this is to deliver transparency in whole system solutions, embed whole systems thinking internally, support vulnerable consumers and communities, and consider the impact of actions on the environment.

While the SPEN whole system plan has developed considerably from draft plan stage, the proposed approach appears to be a statement of intent and strategy without a detailed delivery plan. It is clear SPEN appreciates the need for whole system benefits to go beyond just electricity networks, but we consider that the plan could go further in proactive actions that will deliver significant benefits in heat and transport, for example. While internal organisational change and focus will be important, the plan suggests an inward-looking priority and it may take time to make the desired transformation to benefit consumers.

### 5.4 Other outputs

#### 5.4 (i) Environmental Action Plan

SPEN have a mature and comprehensive EAP which shows sophisticated understanding of issues (including links to UN SDGs) and is framed with an overarching goal of achieving a sustainability step change. It contains clear commitments with associated outcomes for all the key areas we looked at. One criticism would be that its length (and repetition) means that it is not an accessible document.

SPEN have validated SBTs for scopes 1,2 and 3 emissions with a 1.5°C trajectory. They are committing to an ambitious 67.2% reduction from 2018/19 baseline in BCF and 2035 Net Zero target (aligned with the SBTi definition) which has strong stakeholder support. They are also targeting a substantial reduction in scope 3 emissions via an impressive target of 80% of strategic suppliers (by value) to have their own SBT. The plan is the clearest of all DNOs about the need to consider steps on scope 3 emissions and embodied carbon in tandem. SPEN are also committing to be carbon neutral across scope 1 and 2 emissions, excluding losses, from 2023. This will require substantial offsetting. SPEN's carbon removal proposal, which is required to deliver this, is still under development but we commend a focus on environmental restoration options, including peat restoration.

Fleet electrification plans are particularly ambitious but there is little exploration of the cost benefit as compared with other measures. The target appears to derive from a combination of Group policy, regional targets and SPEN ambition: this level of ambition may be appropriate, particularly given the regional factors, but the costs look high and there is no discussion of other fuels.

On $SF_6$, there is a comprehensive strategy to manage leakage and the expected commitment to seek to avoid adding to bank where possible, but no explicit plans to introduce non-$SF_6$ assets. However, there is a commitment to require use of equipment with substantially lower leakage rates than international standards permit.

The losses strategy emphasises the leading role which SPEN are playing in DNO joint work. There is a specific commitment to avoid 36GWh of losses over the ED2 period – not particularly ambitious, but welcome as a definite target.

Another element of the losses strategy is the purchase of a mobile asset assessment vehicle (MAAV) to identify faults rapidly and therefore reduce losses. This is the subject of a CVP bid, which is further discussed in SPEN's CVP section.

### 5.4 (ii) Vulnerability strategy

This remains a strong strategy. It is built around clear areas of focus, makes good use of data and is underpinned by a long-term vision for SPEN's role which, if used well, should support more strategic decision-making that extends beyond the period of the next price control.

In terms of PSR reach, their commitment to register 80% of customers across every needs code appears to be among the most ambitious. They also make the most stretching and meaningful commitment around PSR quality – which is to ensure that a minimum of 60% of data on the PSR is 'fully validated'. In July, we queried what this meant in practice and the final plan adds useful detail explaining that it will include a dedicated team focused on updating PSR data, buying external data to fill in gaps where necessary, and introducing 'self-serve' functionality so that customers can update their own details when prompted.

The strategy also recognises the need to take a targeted approach, especially when delivering support in a power cut, as people's needs will differ greatly. The strategy says that SPEN staff will proactively capture the specific needs of customers when they have contact with them, so that they are able to meet those needs in future. This is a valuable activity – but we were unclear what proportion of customers would have their needs captured in this way, and how SPEN would understand how effective they had been at meeting those needs in the case of a power cut.

The targets SPEN have set out for their fuel poverty work are middling compared to other DNOs, but the targets still represent a significant increase from the scale of its ED1 activity. They commit to 'target' 40k customers in the period and to deliver benefits with a value of £28m. We challenged SPEN to provide more evidence that this level of increase was deliverable in practice. In response they clarified that they have considered requirements for headcount, IT and external contracts and factored the cost of these into the plan. They have also restructured their customer service directorate to have people focused on key initiatives, who will work closely with a new ‘transformation’ directorate. This is relevant detail, but evidence from real-world tests or trials that show that SPEN can operate at this scale and deliver the promised benefits in practice would have been more compelling.

In terms of help with the energy transition, SPEN aim to ‘target’ 40k customers with support around low-carbon technologies based on an ‘LCT risk score’ that they have developed. The support offered will include an advice line on costs, the different solutions available and the benefits these can provide. Then, through this generic advice gateway, some customers will be able to access more personalised support including a ‘tailored plan’ and ‘hand-holding’ right through the process from selecting to deploying technologies. We were unclear how many customers were likely to receive this more personalised support.

SPEN set out a clear background rationale for who they will target and why in this area, but some real-world trials to understand the appeal and impact of this type of service in practice would have been much more valuable. As with other DNOs, we would encourage SPEN to do that work before it starts to commit significant resources to this area.

Another strong feature of SPEN’s approach remains their ‘coalition of partnerships’. This shared governance approach, with an independent Chair and expert advisory panel, has the potential to take the partnership-working that all DNOs use in this area to another level of effectiveness. We particularly welcome the promise of annual ‘impact reports’, signed off by the SPEN Board, which will aim to validate that SPEN is delivering more value to society by running this model than by supporting individual customers themselves.

SPEN have further proposed a CVP related to supporting vulnerable customers through the low carbon transition, which is discussed in SPEN’s CVP section.

### 5.4 (iii) Reliability

SPEN are proposing more stretching reliability targets in their final plan compared with their first draft in July. In particular, they are proposing among the most significant reductions of all DNOs for the number of minutes customers lose to power cuts. If delivered, these targets would mean that their customers in both regions would lose among the fewest minutes to power cuts each year of all network customers. When Ofgem sets the final IIS targets for SPEN (and all DNOs), it will need to ensure that the costs and rewards they drive represent good value for customers when weighed against affordability and the other investments that are needed in ED2. It was unclear to us whether this balance has been struck appropriately by the forecasts set out in SPEN’s plan. SPEN have also set themself a more stretching target in relation to worst-served customers. In July, they planned to improve reliability by 25% for c.2,400 worst-served customers. Now they are targeting an ‘improvement of 33%...in the number of interruptions’ customers experience. However, they acknowledge that the service received by these customers may still classify them as ‘worst served’ even after the improvements are delivered.

*Table 76: SPEN's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with SPEN's performance in ED1.*

| | ED2 Average | | | |
|---|---|---|---|---|
| | CI | CML | CI | CML |
| SPD | 37 | 21 | 37 | 21 |
| SPMW | 24 | 17 | 24 | 17 |

| % change from ED1 Average | | | |
|---|---|---|---|
| CI | CML | CI | CML |
| -17% | -32% | -15% | -27% |
| -26% | -45% | -22% | -37% |

## 5.5 Consumer Value Propositions

*CVP1: Direct low carbon transition support to vulnerable customers – partial support*

SPEN's proposed CVP helps a targeted group of vulnerable customers to reduce energy bills and carbon emissions by funding distributed demand response technology equipment and increasing the uptake of smart meters. The estimated cost is £14.7m (£12.2m for the demand reduction technology; £2.5m for smart meter take-up) with a net value of £7.3m (£6.4m for technology; £920k for smart meter take-up).

For the demand reduction technology, SPEN say that pilot work carried out in its area by a partner has identified that 'home shedding' equipment can save an average of 8-12% on a customer's electricity bill (or an average of c.£100 a year) – 'nearly matching the distribution charge'.

The 'technology solution' component would focus initially on 40k priority households including customers in fuel poverty and those 'off-gas grid'. It proposes a clawback mechanism if it fails to install the technology in 40k homes as promised.

The 'smart meter uptake' component would involve an awareness campaign delivered through local partners targeted on areas with high concentrations of 'hard to reach' customers. It aims to result in the installation of 136k additional meters. It offers a similar clawback for any meters not installed.

As with other DNOs, we do not support the smart meter initiative as suppliers already have an obligation to do this work. The technology solution has potential but, as with other CVPs proposing various types of demand control technology, we were not clear that DNOs are best placed to deliver this type of solution. However, SPEN's proposal does have the merit that it can be targeted, and the savings are backed by preliminary pilots. If it goes ahead, we would suggest that the clawbacks should relate to any failure of the technology to deliver the scale of savings promised, not just to any failure to install the technology.

*CVP2: EV Optioneering – not recommended*

For this CVP, SPEN will work with 37 Local Authorities in their area to identify locations: (a) where there is no market interest in installing public EV charging infrastructure; and, (b) where households have limited off street parking or personal charge points. The optioneering reports produced for Local Authorities can then be used as the basis for a tendering the operation (and potentially ownership) of public EV charging infrastructure. The cost of this proposal is £5.4m (in baseline expenditure and primarily FTE costs) and SPEN has estimated the total gross benefits (societal and financial) to be £15.8m.

The Challenge Group recognises the importance of ensuring that there is an adequate charging network for everyone to facilitate the transition to electric vehicles. However, as described, the activities that SPEN have described in this proposal do not appear to go far beyond what could be considered as business as usual for a DNO/DSO. Funding through a CVP is not considered to be the most appropriate mechanism.

*CVP3: Mobile asset assessment vehicle – not recommended*

An element of SPEN's EAP loss strategy is the proposed procurement of a Mobile Asset Assessment Vehicle (MAAV) to detect stray and contact voltages that result from faults on their network and on connected third-party equipment. Early detection of faults helps reduce losses, improve network performance and improve customer safety. The cost of the MAAV over ED2 is £10m (in the baseline) with a gross benefit estimated by SPEN at £10.8m.

Whilst the Challenge Group recognises the potential benefits of the MAAV, in Annex 5C.2 SPEN admit that these benefits are difficult to quantify. The benefits case relies heavily on societal cost of avoided carbon due to reduction in losses but little real-world evidence to support these numbers. Given the marginal cost-benefit case, we would like to see further demonstration and evidence of these claimed benefits. If this has a 5-year payback, we consider that this may best be considered as an efficient baseline expenditure and not subject to an additional CVP incentive.

*CVP4: Advanced Fault Level Management – not recommended*

SPEN propose to roll out Real-Time Fault Level Monitoring (RTFLM) at 22 sites in SPD and 16 sites in SPM to monitor fault levels in real time. They also propose to install Active Fault Level Monitoring (AFLM) at 1 site in SPD and 2 sites in SPM to manage the fault levels in real time. Together, these two innovations should give SPEN greater visibility of network fault levels and enable them to accommodate more generation whilst triggering fewer equipment replacements / network reinforcement. The cost of this proposal is £2.4m and the estimated net benefits are £34.1m, primarily through the deferred cost of network reinforcement for increased fault levels.

The Challenge Group recognises that fault level management can defer reinforcement at a lower cost to consumers. However, as described, the activities that SPEN will undertake as part of this proposal do not appear to go far beyond what could be considered as business as usual for a DNO/DSO. Funding through a CVP is not considered to be the most appropriate mechanism.

## 5.6 Finance

We are pleased to note that, unlike its draft plan, SPEN's BP contains an unambiguous statement of financeability (though not fully reflected in the board assurance statement – see below). It has not, however, amended its Alternative Assumptions for either the cost of debt or the cost of equity allowance and the presentation of its financeability analysis remains unhelpfully confusing.

SPEN target a rating of A3/Baa1 in the base case for both the Notional and Actual Companies. Ofgem is clear that it considers it is for individual DNOs to determine their target ratings. We accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status but we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. Despite SPEN's references to earlier price controls, we regard A3/Baa1 as at the upper end of the acceptable target range and certainly do not consider that a company needs to demonstrate an expectation of that rating in order to be deemed ‘financeable’.

SPEN disagree with some of Ofgem’s W/As, describing them (unnecessarily provocatively in our view) as ‘errors’. Although they reject the concept of the OW, they have carried out its analysis, as required, on the basis of a cost of equity of 4.65% (i.e. 4.4% +0.25%) and a cost of debt of 2.09%. They have also carried out analysis on the basis of their proposal for a cost of equity allowance of 6.21% and a cost of debt, inclusive of various issue costs etc. equivalent to 2.4%. The results of both sets of analysis are presented (although unhelpfully intermingled with each other). The BP states that both SPD and SPM would achieve a rating of Baa1 (Notional) and A3 (Actual) using Ofgem’s W/As. This is supported by the results of both the Base Case modelling and the sensitivity analysis which show a degree of stress in the most difficult downside cases of totex overspend and RoRE underperformance in the Notional Company for both licensees (but not with a rating below Baa2 in either case). For the Actual Company, the results are very robust for both licensees, dropping to Baa1 only in the SPD totex overspend case and rated A2 or A3 for all other sensitivities. We regard the analysis overall as a clear demonstration of financeability at a 4.65% equivalent cost of equity and consider that, although results are not shown, at 4.4%, financeability with that cost of equity allowance might well be achievable.

We made clear to SPEN that we did not consider the cost of equity allowance of 6.21% which they proposed in their draft plan to be in the best interests of consumers and are sorry that they have not thought it appropriate to reconsider this proposal. As indicated above, we do not consider a cost of equity allowance at this level is necessary for SPEN to achieve financeability.

We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions. SPEN put forward a number of arguments in support of their proposal for a higher allowance which we do not find persuasive and which we address above.

SPEN’s analysis has been based on 60% gearing, the capitalisation rate inferred from their expenditure projections (72% for SPD and 70% for ManWeb) and depreciation over 45 years (although they say they will ‘keep an eye on’ the evolution of totex over the course of the price control). There is a certain amount of evidence that they have given at least some consideration to the potential to improve financeability through alternative rates of gearing, depreciation and capitalisation, but further work may be required if Ofgem’s final determination is based on a cost of equity allowance below 4.65%.

SPEN have modelled on the basis of Ofgem’s cost of debt W/A. As noted in our commentary on the company’s draft plan, it is for individual DNOs to determine their debt funding strategies and the extent to which they implement those strategies on a group-wide basis. However, we can see no reason for a small company premium in relation to the SPEN licensees. SPEN are also concerned that their position is unfairly impacted by the fact that Ofgem’s W/As provide for 25% index-linked debt: neither of its licensees carries any ILD. It is true that the proportion of debt contracted on an index-linked basis is rather less than 25% across the DNO sector as a whole but we regard 25% as a reasonable assumption for the Notional Company, rather below the assumption used in other recent utility price controls. ILD was an option which was clearly available to SPEN in the past but which it elected not to take advantage of. It is also an option which is likely to be available to it in the future (though we note that its own assumptions provide for its Actual Company to hold none of its debt on that basis going forward: they are clearly at liberty to vary that assumption).

As noted above, the Financeability section of SPEN's BP contains an unambiguous statement (page 170) that the plan is financeable on both a notional and an actual capital structure basis using Ofgem's cost of capital W/As. We consider this statement to be well supported by the results of its analysis. We are surprised, therefore, that Annex 5D.1 (Finance) contains the statement (Para 3.6.5) that 'Ofgem's financial package is not financeable and needs to be modified…'. Further, the 'Financeability Statement' in SPEN's Board Assurance Statement focuses on its disagreement with 'a number of aspects of Ofgem's approach to the assessment of the cost of capital for RIIO-ED2'. A financeability statement is an important Ofgem requirement and we consider the inclusion of contradictory statements in this regard in the body of the plan and its appendices, cast an unhelpful degree of ambiguity over the position. We consider the lack of clarity in this area to be a serious shortcoming, particularly as the results indicate that a wholly unambiguous statement could be made without difficulty.

# 6. Company report – SSEN

As a summary, we have assigned SSEN's Business Plan the following ratings:

*Table 77: SSEN BP scores*[17]

| | |
|---|---|
| Track record from RIIO-ED1 | 2 |
| Scenarios and forecasts | 2 |
| Totex: LRE, incl. anticipatory investment | 3 |
| Totex: NLRE, incl. asset health | 2 |
| Totex: Network operating costs | 2 |
| Totex: Non-operational costs | 2 |
| Totex: Ongoing efficiency and RPE | 2 |
| Totex: Uncertainty mechanisms | 2 |
| Outputs: DSO and digitalisation strategy | 3 |
| Outputs: Whole system strategy | 4 |
| Outputs: EAP | 3 |
| Outputs: Vulnerability strategy | 3 |
| Outputs: Reliability | 3 |
| Finance | 3 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of SSEN's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 144% from ED1 levels and we are concerned that this may not include benefits from network capacity optimisation.
- **DSO and whole system –** SSEN are targeting annual flexibility actions of 5,000MW, delivering benefits of £18-46m over ED2. We are concerned that these benefits appear low for the proposed actions and that they are not reflected in load-related capex forecasts.
- **Costs –** Baseline totex has reduced by around £100m since the draft plan but is still forecast to increase by 46% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that underlying cost increases for the same asset basis are unjustified.
- **Risks and uncertainty –** SSEN have proposed uncertainty mechanisms which could add £1,048m or 26% of totex. We are concerned that some of these costs may not offer value for money and may already be included in baseline expenditure.
- **Vulnerability –** SSEN propose a ten-fold increase in the number of customers in fuel poverty that they plan to support. We would like to see SSEN provide real-world evidence that they can deliver this scale of increase.
- **Finance –** In our view, SSEN's modelling provides a clear demonstration of the financeability of their BP on the basis of Ofgem's Working Assumptions (W/As) for the cost of capital. We would like to understand why their Board qualified their financeability

[17] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

statement with 'technically' financeable. We would also like to understand why they have not fully explored all of Ofgem's 'levers' to improve financeability, including gearing and a dividend restraint or new equity, which we consider could well result in their plan being financeable with a cost of equity allowance below 4.65% (to the benefit of SSEN's customers).

## 6.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

Key performance measures are shown in the tables below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 78: SSEN ED1 performance summary*

| ED1 performance (2021 RRP) | SSEN |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 0.5% |
| Customer service (BMCS) | 0.3% |
| Time to connect (TTC) | 0.1% |
| **Output incentives total** | 1.0% |
| **Totex efficiency incentives** | (0.8%) |
| **Operational RoRE** | 6.2% |

**ED1 - Totex (2021 PCFM)**

| £m (2012/13 prices) | SSEN |
|---|---|
| Totex allowance | 3706 |
| Totex actual/forecast | 3710 |
| % totex (under)/overspend | 0% |
| % LRE (under)/over spend | (25%) |
| % Totex (excl. LRE) (under)/overspend | 3% |

Overall, we note that SSEN expect their ED1 totex outturn to match their allowance. However, they are showing an underspend of 25% in load-related capex, largely attributable to lower-than-expected LCT growth. Once load-related capex is excluded, overall outturn totex expenditure is expected to be 3% higher than the allowance.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) reward is the lowest of all DNOs and the customer service incentive (BMCS) is also amongst the lowest.

## 6.2 Costs, scenarios and forecasts

### 6.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios that SSEN have examined and that these scenarios appear to be consistent with Net Zero targets. We note that, as in the draft Business Plan, the DFES Consumer Transformation scenario has been used as the baseline future pathway for the SSEN Business Plan. The plan has used this scenario for funding in years 1 and 2, with a lower electricity heating scenario (DFES System Transformation) being used for the following years.

By the end of ED2, SSEN forecast they will have connected:

- 994k EVs and 512k heat pumps under their Best View (Baseline) scenario; and,
- 1300k EVs and 800k heat pumps under their Upper View scenario.

These scenarios are presented below as 'Best View' and 'Upper View'.

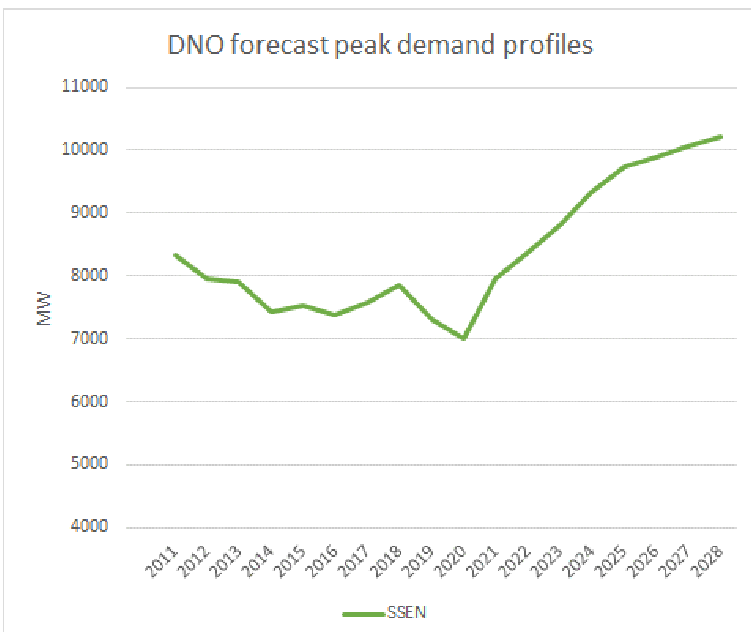
*Table 79: SSEN low-carbon technology scenarios*

SSEN have around 13% of the networks' total customer base. The forecast number of EVs and heat pumps in the Best View scenario across this customer base in 2028 is broadly in line with the ESO 2021 FES Consumer Transformation or Leading The Way scenarios, which forecast around 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers.

The submission of demand profiles in the BPDTs shows an increase of around 46% between 2020 and 2028, which is inconsistent with the equivalent peak demand increase of 11% forecast in the ESO 2021 'Consumer Transformation' scenario and differs greatly from the peak demand numbers submitted in the draft Business Plan in July.

SSEN contend that national peak demand is not a good comparator with their network demand, which has been derived from their local forecasts, including for large demand connections. The view of the Challenge Group is that this large demand increase has not been adequately explained.

*Chart 25: SSEN forecast peak demand profile*




Overall, we consider that SSEN have undertaken effective scenario planning. However, we are concerned that the forecast demand growth assumptions have not been fully explained and the forecast is also inconsistent with national energy scenarios.

### 6.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered; and,
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages, and do not include any normalisation adjustments.

The SSEN ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £4,018m and is a 46% increase on the annual average expenditure rate during ED1. The forecast has marginally reduced from the £4,132m figure submitted in the SSEN draft plan. The following table compares the SSEN cost submissions between ED1 actuals/forecasts and ED2 forecasts. It also compares the draft and final plans[18].

We note that the SSEN plan has included £1,048m of uncertainty mechanism costs in the baselines. The table, below, shows a resultant totex increase of 50% once uncertainty mechanisms, real price effect and ongoing efficiency adjustments are removed.

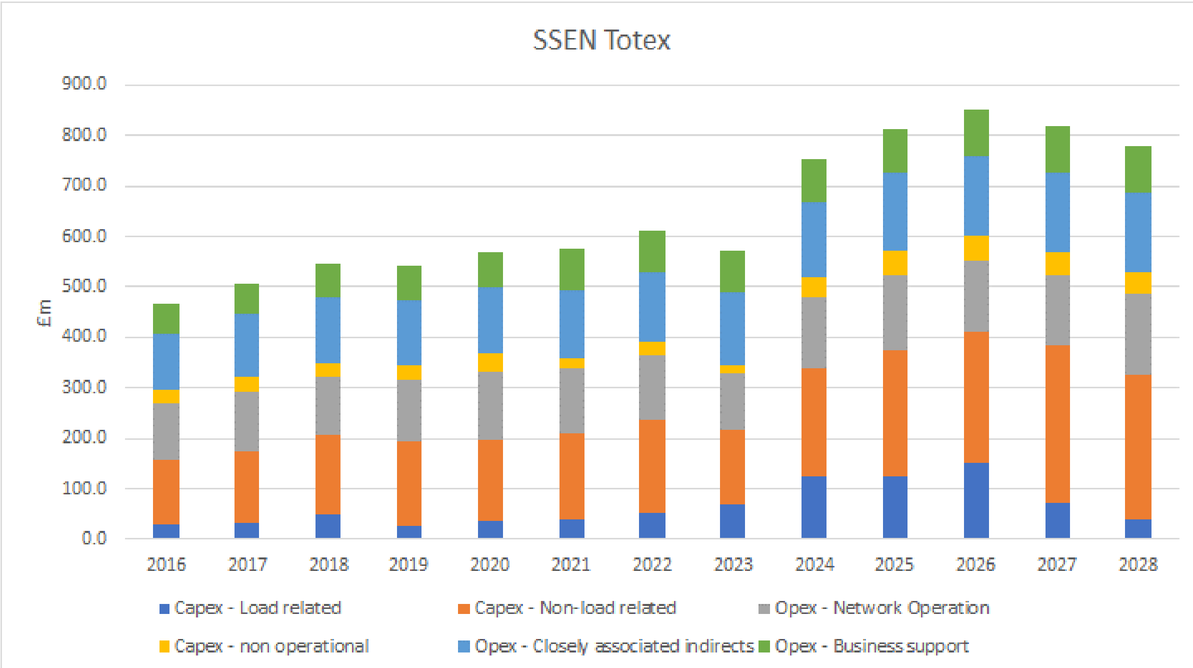
*Table 80: SSEN overall totex comparison*

| SSEN | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| **Overall** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Capex - Load related | 334.8 | 510.2 | 41.8 | 102.0 | 144% | 310.3 | 543.1 | 38.8 | 108.6 | 180% |
| Capex - Non-load related | 1258.7 | 1322.4 | 157.3 | 264.5 | 68% | 1281.2 | 1345.1 | 160.1 | 269.0 | 68% |
| Opex - Network Operation | 974.1 | 734.8 | 121.8 | 147.0 | 21% | 965.2 | 734.6 | 120.6 | 146.9 | 22% |
| Capex - non operational | 207.8 | 220.8 | 26.0 | 44.2 | 70% | 212.1 | 284.1 | 26.5 | 56.8 | 114% |
| Opex - Closely associated indirects | 1052.9 | 781.2 | 131.6 | 156.2 | 19% | 1058.3 | 783.2 | 132.3 | 156.6 | 18% |
| Opex - Business support | 565.3 | 448.4 | 70.7 | 89.7 | 27% | 567.0 | 442.3 | 70.9 | 88.5 | 25% |
| **BPDT Totex** | 4393.6 | 4017.8 | 549.2 | 803.6 | 46% | 4394.1 | 4132.4 | 549.3 | 826.5 | 50% |
| **Baseline totex after OE/RPE adjustments** | | | 549.2 | 822.3 | 50% | | | | | |
| **Baseline totex with UMs (excl. Access SCR)** | | | 549.2 | 1031.9 | 88% | | | | | |

A profile of the totex and main expenditure categories is shown below, showing a significant increase at the start of ED2, especially in non-load capex.

*Chart 26: SSEN overall totex profile*

[18] Note: These totex figures exclude 'other costs outside the price control' The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for most ongoing expenditure, and we have scrutinised reasons for increases from these levels. Our assessments for these individual cost categories are set out, below. We are seeking to understand the justifications for these potential increases.

### *ii.a. Totex: LRE*

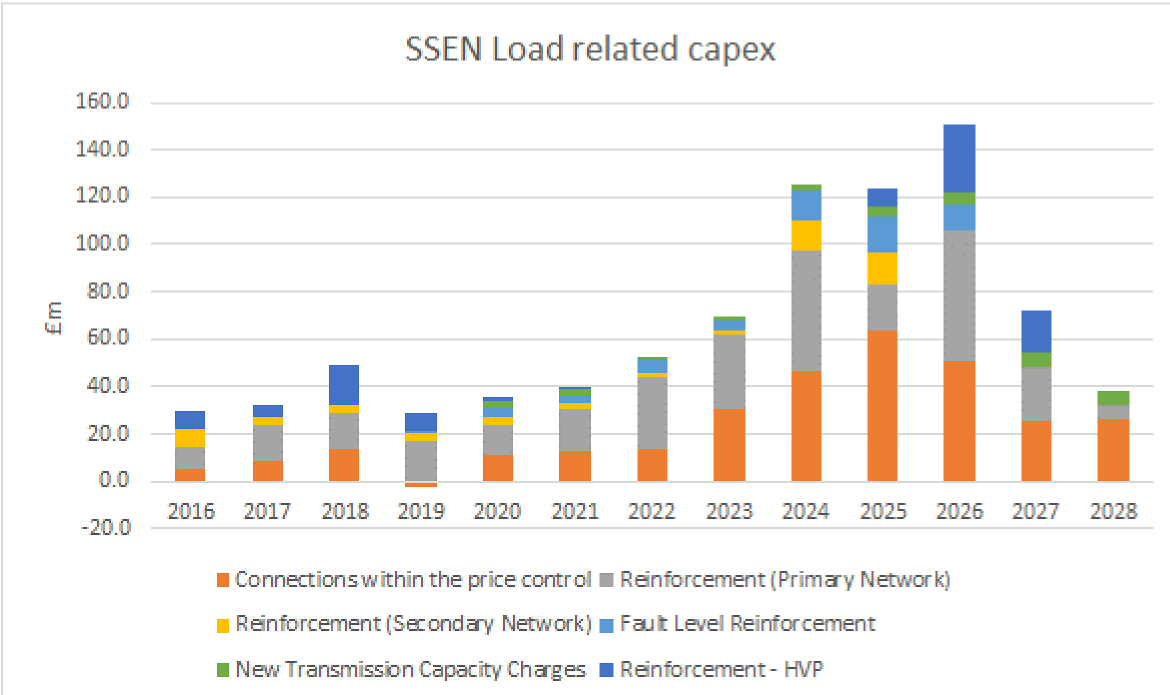
The SSEN bid for baseline LRE is £510m, which represents a 144% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual categories, with reinforcement relating to primary networks and connections showing significant increases. However, unlike other DNOs, secondary network reinforcement does not show a significant increase.

*Table 81: SSEN load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Connections within the price control | 93.2 | 212.3 | 11.7 | 42.5 | 264% |
| Reinforcement (Primary Network) | 150.2 | 154.8 | 18.8 | 31.0 | 65% |
| Reinforcement (Secondary Network) | 25.5 | 26.1 | 3.2 | 5.2 | 64% |
| Fault Level Reinforcement | 19.5 | 39.5 | 2.4 | 7.9 | 225% |
| New Transmission Capacity Charges | 8.3 | 23.2 | 1.0 | 4.6 | 346% |
| Reinforcement - HVP | 38.1 | 54.2 | 4.8 | 10.8 | 128% |
| **Total load related costs** | 334.8 | 510.2 | 41.8 | 102.0 | 144% |

A profile of the LRE expenditure categories is shown, below. It shows a significant increase at the start of ED2, especially in connections and primary network reinforcement. The profile then declines rapidly in the latter part of ED2 which may reflect reliance on SSEN's proposed LRE uncertainty mechanisms. While we support the need for investment in network capacity to enable Net Zero, we did not consider the baseline or uncertainty profile proposed by SSEN was justified.

*Chart 27: SSEN load-related capex profile*




We are concerned that SSEN's plan has not fully considered the availability of current capacity headroom, and the benefits from flexibility and smart control to enhance network utilisation. While SSEN have provided evidence to explain increase expenditure in the early part of ED2, for example due to site specific security standard compliance, we are concerned that the underlying LRE profile did not appear to reflect the potential LCT growth profile timing over ED2.

We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

***ii.b. Totex: NLRE***

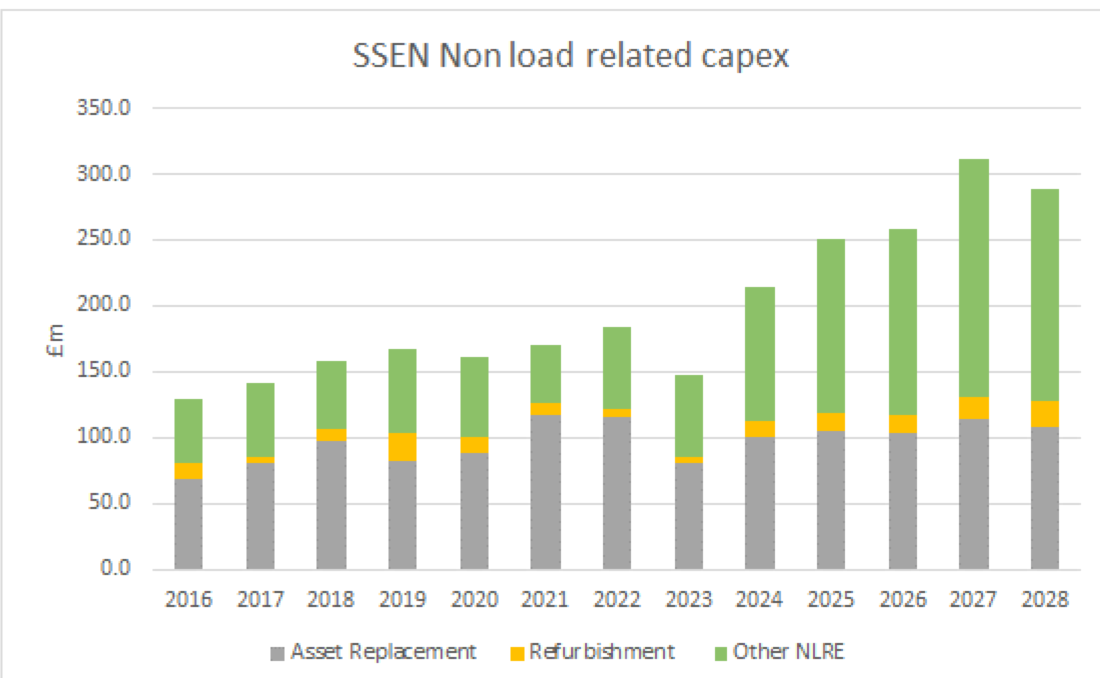
The SSEN bid for baseline NLRE is £1,322m, which represents a 68% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with reinforcement relating to asset replacement/refurbishment, and operational IT and telecoms showing significant increases in particular. We note that this NLRE forecast includes £164m of additional Scottish Islands resilience expenditure.

*Table 82: SSEN non-load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Non Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Diversions (Excluding Rail Electrification) | 106.4 | 112.0 | 13.3 | 22.4 | 68% |
| Diversions Rail Elec | 9.9 | 0.0 | 1.2 | 0.0 | -100% |
| Asset Replacement | 730.7 | 531.2 | 91.3 | 106.2 | 16% |
| Refurbishment | 79.8 | 74.7 | 10.0 | 14.9 | 50% |
| Civil Works Condition Driven | 36.8 | 28.5 | 4.6 | 5.7 | 24% |
| Operational IT and telecoms | 48.5 | 114.7 | 6.1 | 22.9 | 279% |
| Blackstart | 5.7 | 5.6 | 0.7 | 1.1 | 56% |
| BT21CN | 10.7 | 0.0 | 1.3 | 0.0 | -100% |
| Legal & Safety | 33.6 | 14.5 | 4.2 | 2.9 | -31% |
| QoS & North of Scotland Resilience | 99.4 | 62.5 | 12.4 | 12.5 | 1% |
| Flood Mitigation | 21.9 | 24.2 | 2.7 | 4.8 | 77% |
| Physical Security | 0.0 | 44.0 | 0.0 | 8.8 | n/a |
| Rising and Lateral Mains | 3.7 | 29.3 | 0.5 | 5.9 | 1169% |
| Overhead Line Clearances | 43.2 | 60.5 | 5.4 | 12.1 | 124% |
| Worst Served Customers | 3.6 | 3.3 | 0.4 | 0.7 | 47% |
| Environmental Reporting & Losses | 24.9 | 133.5 | 3.1 | 26.7 | 757% |
| HVP | 0.0 | 83.9 | 0.0 | 16.8 | n/a |
| **Total non load related capex** | 1258.7 | 1322.4 | 157.3 | 264.5 | 68% |

A profile of the NLRE expenditure categories (including uncertainty mechanisms) from 2016 to 2028 is shown below, showing a significant potential increase over ED2.

*Chart 28: SSEN overall non-load capex profile*



We recognise that there are some upward cost drivers in relation to DSO and network visibility investment, and from accelerated PCB removal. However, we do not think the scale of NLRE expenditure increases for ED2 (even without the uncertainty mechanism costs) have been justified given the asset base remains largely the same as for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We note that SSEN are targeting a network risk target of 31%, resulting in a closing ED2 position of 12.5% above opening. The forecast monetised risk reduction is 46.9 pence per point. We note that SSEN is forecasting at the end of ED2 a network risk of 31% without intervention and a target after intervention of 12.5%. The forecast monetised risk reduction is 46.9 pence per point. We note that SSEN's total network risk target reduction of 14.4% is the lowest of all DNOs and the monetised risk points are the highest.

We note that SSEN consider that their approach does not target the optimisation of asset health, but to focus on assets that are truly 'end of life'. We are concerned that SSEN's NARM asset replacement may not optimise asset health and may also not be efficient. We would ask Ofgem to investigate further.

For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The SSEN profile is shown below:

*Table 83: Low voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| SSEH | 1026 | 469 | 386 | -54% | -18% |
| SSES | 3632 | 2408 | 2669 | -34% | 11% |
| TOTAL | 4658 | 2877 | 3055 | -38% | 6% |

LV poles are a significant element of SSEN's non-load-related Expenditure Plan and, as such, we have examined their EJP in more detail. We noted that detailed analysis of the health and criticality of the wood poles was included. We consider that a good range of options to direct replacement of the poles were evaluated. Overall, we feel that a reasonable justification has been made in this EJP.

Other companies are proposing techniques to prolong the life of new wood poles, such as use of a polesaver, and we would expect SSEN to demonstrate that this has been considered.

### *ii.c. Totex: Network operating costs*

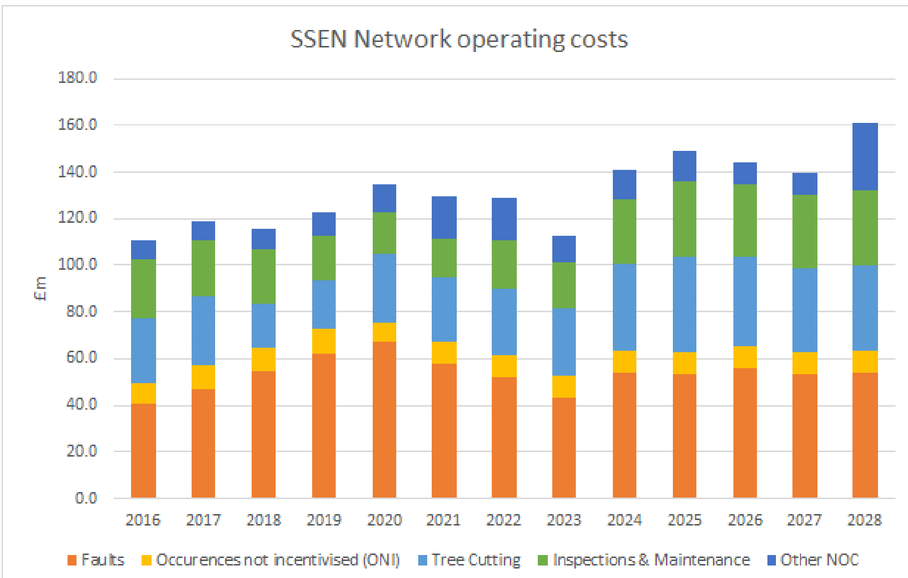
The SSEN bid for network operating costs is £735m, which represents a 21% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with the most significant increases being in Inspections & Maintenance and Tree Cutting. Smart meter costs have decreased.

*Table 84: SSEN network operating cost comparison*

| Opex - Network Operating Costs | Totals ED1 | Totals ED2 | Averages ED1 | Averages ED2 | % change ED1-ED2 |
|---|---|---|---|---|---|
| Faults | 424.0 | 269.7 | 53.0 | 53.9 | 2% |
| Severe Weather 1 in 20 | 0.0 | 19.2 | 0.0 | 3.8 | |
| ONIs | 76.2 | 47.7 | 9.5 | 9.5 | 0% |
| Tree Cutting | 212.9 | 189.6 | 26.6 | 37.9 | 43% |
| I&M | 165.5 | 154.3 | 20.7 | 30.9 | 49% |
| NOCs Other | 78.3 | 48.2 | 9.8 | 9.6 | -1% |
| Smart Meters | 17.2 | 6.0 | 2.2 | 1.2 | -44% |
| **Total Network Operating Costs** | 974.1 | 734.8 | 121.8 | 147.0 | 21% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown below. The profile increases over the first two years of the ED2 period.

*Chart 29: SSEN overall network operating cost profile*




We do not consider that SSEN have justified these cost increases. A 21% increase is significantly higher than other DNOs. Some DNOs have been able to deliver cost reductions in this area and there may be potential for SSEN to also deliver savings.

### *ii.d. Totex: Non-operational costs*

Under this cost grouping we have included business support, closely associated indirects (CAI) and non-operational capex. The SSEN bid is for £448m of business support costs (an increase of 27%), £781m of closely associated indirects (an increase of 19%), and £221m of non-operational capex (an increase of 70%). The combined increase is 27% which is higher than most companies. SSEN have also included increases to non-operational costs in their uncertainty mechanisms which we do not think are justified,

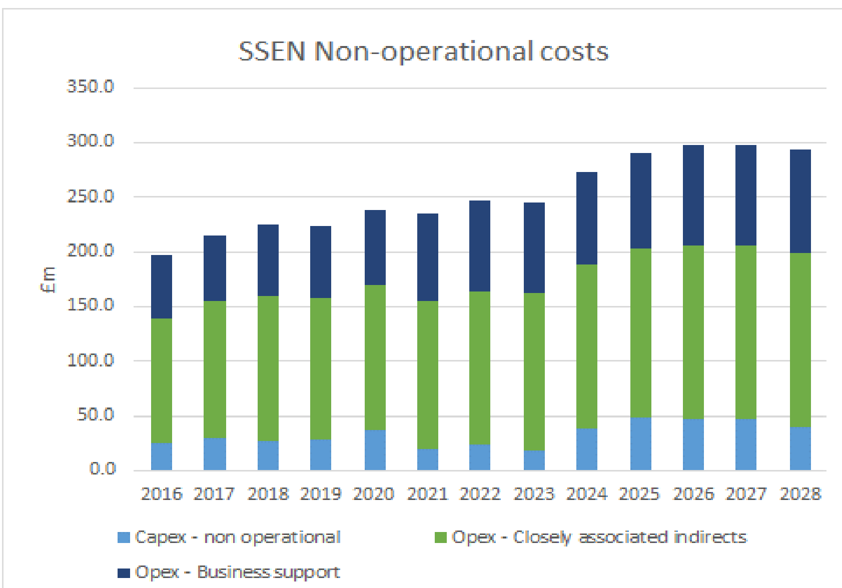
The following table shows the breakdown of these costs by the individual business plan categories.

*Table 85: SSEN non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 223.7 | 166.6 | 28.0 | 33.3 | 19% |
| IT& Telecoms (Business Support) | 275.2 | 239.9 | 34.4 | 48.0 | 39% |
| Property Mgt | 66.4 | 41.9 | 8.3 | 8.4 | 1% |
| **Total Business Support Costs** | 565.3 | 448.4 | 70.7 | 89.7 | 27% |
| **Closely associated indirects** | | | | | |
| Core CAI | 739.3 | 569.6 | 92.4 | 113.9 | 23% |
| Wayleaves | 69.2 | 45.7 | 8.7 | 9.1 | 6% |
| Operational Training (CAI) | 84.2 | 59.8 | 10.5 | 12.0 | 14% |
| Vehicles and Transport (CAI) | 160.2 | 106.1 | 20.0 | 21.2 | 6% |
| **Total CAI** | 1052.9 | 781.2 | 131.6 | 156.2 | 19% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 126.1 | 137.7 | 15.8 | 27.5 | 75% |
| Property (Non-Op) | 23.4 | 35.3 | 2.9 | 7.1 | 141% |
| Vehicles and Transport (Non-Op) | 17.0 | 14.3 | 2.1 | 2.9 | 35% |
| Small Tools and Equipment | 41.2 | 33.4 | 5.2 | 6.7 | 29% |
| **Total non-op capex** | 207.8 | 220.8 | 26.0 | 44.2 | 70% |

A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown, below. The profile shows a gradual increase from the start of the ED2 period and continues thereafter.

*Chart 30: SSEN overall non-operational cost profile*




SSEN provide limited evidence to justify these increases in their business plan. We are concerned that efficiency opportunities have not been sought with corresponding rigour, and these non-operational costs may be overstated as a result.

### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. SSEN's annual ongoing efficiency challenge set out in business plan data tables indicate an overall ED2 saving of 3.5% as a percentage of baseline totex after ongoing efficiency. SSEN are forecasting real price effects over ED2 that total 5.9%.

*Table 86: SSEN Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| SSEN | 235 | 5.9% | 140 | 3.5% | 4018 |

SSEN's RPE forecasts are amongst the highest of the DNOs and we don't consider this has been justified. OE is above the average of the companies, but this appears to be offset by the RPE proposals. We suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 6.2 (iii) Uncertainty mechanisms

As set out above, SSEN have proposed a wide range of bespoke uncertainty mechanisms and reflected these costs in their baseline plan. Costs estimates are taken from business plan data tables and total £1,048m or 26% of their totex bid. In the time available, we have not been able to fully reconcile the potential uncertainty costs with other information provided in company plans. As such we have commented on the principles relating to these risks and mechanisms rather than the costs proposed.

*Table 87: SSEN UMs*

| Category | Risk addressed | Potential cost |
|---|---|---|
| Load-related expenditure | Uncertain load-related investment | £240m |
| Wayleaves and diversions | Uncertain expenditure | £37m |
| Ash dieback | Uncertain expenditure | £48m |
| PCB removal | Uncertain expenditure | £37m |
| Shetland | Uncertain expenditure | £14m |
| Restoration (Black start) | Uncertain expenditure | £21m |
| Hebrides and Orkney HVP | Uncertain expenditure | £276m |
| Subsea cables HVP | Uncertain expenditure | £76m |
| Opex adjuster | Uncertain expenditure | £131m |
| DG monitoring | Uncertain expenditure | £41m |
| Environmental reporting | Uncertain expenditure | £118m |

We agree that it would be appropriate to include LRE uncertainty mechanisms but would like to see that these are appropriately calibrated in terms of costs, volumes and triggers, and ensure that investment is delivered and does not provide windfall gains for companies.

With regard to specific projects such as Shetland, subsea cables, and Hebrides/Orkney, we suggest that they be evaluated by Ofgem and potentially included as reopeners once sufficient evidence of need and value for money is demonstrated. For all these projects, we suggest that Ofgem considers where such projects or alternative non-network solutions could potentially be competitively tendered.

For wayleave compensation, ash dieback, PCB removal, and DG monitoring, we consider that these are business as usual risks that are best managed by SSEN who would be best placed to limit both impact and cost. Our concern is that these risks may already be adequately funded by the baseline expenditure forecasts and these potential additional volume and cost drivers may be overly generous to companies if triggered.

We do not consider that an additional ex-ante opex adjuster for uncertainty mechanisms should be included. This would be difficult to calibrate and may be overly generous to SSEN if triggered.

However, if Ofgem determines that these risks should be included as uncertainty mechanisms, we suggest this should only take place if reasonable expenditure and contingency allowances are not already included in baseline. If applied, the triggers and in-flight expenditure approval processes would also need to be appropriately calibrated.

Overall, we are concerned with the volume, cost and complexity of uncertainty mechanisms being proposed by SSEN. If these are accepted then we consider that a much higher degree of risk is being passed to consumers, and it may be appropriate that SSEN should receive a lower cost of equity allowance as a result.

## 6.3 DSO and whole system

### 6.3 (i) DSO and digitalisation strategy

SSEN's DSO ambition is to allow simple and standardised access to flexibility markets across GB, with leading data, technology and people capabilities. They plan to use a 'Flexibility First' commitment to avoid the need for reinforcement. SSEN plan to build on their participation in the related ENA Open Networks project initiatives, including:

- **Planning & network development –** DFES will be improved in collaboration with other DNOs, aiming to introduce new tools to improve quality of data. They are planning to: have an exchange for data sharing; introduce a network capacity portal to; and, publish an annual Distribution Network Option Assessment.
- **Network operation –** the ENA DSO roadmap will be completed in late 2023 to facilitate data exchange and system visibility; in the meantime, a future flexibility statement has been produced. LV monitoring is also being continued from ED1.
- **Market development –** SSEN plan to adopt common ENA processes.

SSEN are proposing to spend £94m on DSO activities in ED2 (including 139 DSO staff by 2028) and are targeting 19% of secondary substations to have metering installed. SSEN propose to invest £27m to scale up workforce capabilities, and a further £45m in various Information

Technology (IT) and Operational Technology (OT) projects; this will underpin their ability to deliver the primary DSO roles.

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| SSEN | 10,223 | 3222 | 5000 | 49% | 155% | 18-46 |

The DSO and flex savings of £18-46m represent only the flex savings associated with load reinforcement deferral. It does not include flex connection benefits or broader optionality benefits.

SSEN are proposing that 5,000MW of demand (or 49% of peak demand) will be met through flexibility services. This target covers LRE deferral/avoidance, flexible connections as well as broader flexibility services such as outage management. Over the longer term, they plan to grow flexible connections to 3.7GW of capacity to avoid £418m of reinforcement cost.

Overall, the DSO vision of the DSO facilitation role is well described, but the plan appears less cohesive in the way this role will be delivered, and the delivery of flexibility targets and benefits is not well evidenced. The DSO strategy appears more an evolution of the work completed in ED1 to meet Ofgem's baseline expectations. Potential benefits from deferring network reinforcement are evaluated in the EJPs/CBAs for each scheme. It is difficult to follow how these are aggregated to the total claimed benefit.

***Digitalisation***

The digitalisation plan includes additional details addressing delivery and interdependencies, which is welcome. But we consider that this still remains at a relatively high level and we are concerned that it may not deliver the digital transformation ambition.

### 6.3 (ii) Whole system strategy

SSEN's plan focuses on three key steps to achieving their long-term vision for whole systems:

- Reflecting on progress and lessons learned;
- Reviewing internal processes to embed and promote whole systems solution delivery; and,
- Embedding whole systems thinking into decision making.

SSEN propose to:

- Establish a temporary whole systems change management team to take ownership of the change management required to achieve this plan and embed it into BAU by the end of ED2;
- Redefine internal processes to reflect whole systems thinking. Key activities include lessons learned and review sessions with stakeholders, and an annual report on progress;

- Engage with other partners including ENA Open Networks to develop whole systems approaches;
- Train whole system decision makers;
- Introduce whole system metrics to track progress;
- Review all ED2 load investments above £2m for whole system solutions;
- Invest in open data and a data portal for third parties;
- Engage with LAs on local authority energy plans; and,
- Support 200 community groups and 72 LAs to help them transition to Net Zero.

Overall, the SSEN whole system plan appears to recognise the need for a step change in whole system activities and has put steps to realise change internally and externally. The whole system plan is based around a business transformation plan to embed new thinking and practices across the organisation, which is welcome. Proposals to work with Local Authorities and community groups to help them transition to Net Zero appear promising. However, the plan does appear to be predominantly focused on electricity system activities and the ultimate identification and delivery of whole system benefits is uncertain.

## 6.4 Other outputs

### 6.4 (i) Environmental Action Plan

SSEN have articulated a clear vision for their environmental strategy and recognised the challenge they face to raise their performance in ED2 in comparison to ED1. They have linked their strategy very clearly to the UN SDGs. We welcome the emphasis on governance, reporting and interaction with stakeholders. There are many commendable aspects of their EAP, including extensive benchmarking but there are also areas where there seems to be a lack of clarity, particularly in relation to the impact of different measures.

SSEN now have a validated SBT with a 1.5°C trajectory. SSEN have also chosen to set a scope 3 target based on 35% percent of suppliers by spend adopting an SBT. We noted that SSEN's plan seems to show a good understanding of scope 3 emissions. However, we would have welcomed more discussion of the expected outcome of this target, including whether it is expected to change supplier behaviour and an awareness of what percentage of suppliers currently have an SBT (as noted at least one DNO is targeting a much higher percentage take-up by end of ED2).

SSEN have also set a target to reduce embodied carbon by 5 – 10% by 2033. Whilst we commend their decision to set a target in an area where most other DNOs have not committed to specific action, aside from measuring and aiming to reduce it, it does not seem to us to be at all ambitious. This is particularly so given the scope 3 emissions target and, for example, the level of ambition on embodied carbon in transmission plans, and it is not clear how this reduction will be measured.

SSEN has a relatively ambitious fleet electrification target, in part due to the Group commitment to EV100. We would have liked to see more evidence of consideration of options, such as electrification of fleet versus other fuels and recognition of the potential cost savings.

We welcome that on $SF_6$ SSEN has responded to stakeholder encouragement to set an ambitious leakage reduction target which will combine replacement of assets with worst performance with better identification.

On losses, SSEN recognise the importance of taking proportionate action to reduce losses as well as relying on decarbonisation of the grid. Specific measures in their strategy include TASS as well as deployment of loss reduction technology.

We are pleased to note that in response to stakeholder input, nature-based solutions for longer-term carbon mitigation now include peatland restoration and restoration of native woodlands, although stakeholders also mentioned wetlands which do not seem to have been pursued.

A CVP proposal to fund seagrass planting is further discussed in SSEN's CVP section.

### 6.4 (ii) Vulnerability strategy

SSEN have made a number of changes to their strategy since their July draft plan and we think it is now acceptable.

In terms of PSR reach, they commit to 'close the PSR gap' to 28% at the end of ED2 from the current 31.5%. The collaborative work between the DNOs and Ofgem on consistent measures will need to ensure that commitments in the DNOs' plans are made on a like-for-like basis. But, with that important caveat, this target appears to be among the higher ones in the plans, and SSEN would seem to be starting from a relatively strong position. Like some other plans, SSEN's strategy talks about capturing more tailored information about different customers' circumstances and needs so that it can understand better how to meet those needs. This programme includes building a 'self-serve' capability so that customers can update their own details. This is a valuable focus but we were unclear how SSEN would ensure that as many customers' needs as possible are actually captured, and how they would measure their success in delivering on those needs, particularly in the case of a power cut.

In terms of fuel poverty, SSEN are another DNO committing to a significant increase in the scale of its activities. They say that they have increased the number of households that they help with fuel poverty and energy efficiency support from just 34 in 2016/17 to 3,762 in 2020/21. But, during ED2, they are committing to supporting 10k households a year (or what it says is the equivalent of 114k customers over the period). This is the same commitment that SSEN made in July, but they say that they have doubled the target since the early stages of planning in response to stakeholder feedback. Like other DNOs, they fail to provide any real-world evidence (for example, from trials) that they can deliver measurable and meaningful benefits at this scale, but we do note that they commit to 'amend our ED1 pathway' to help achieve their target. Demonstrating that they can successfully scale up their ED1 activity will be an important way to build confidence in their ED2 ability to deliver. Encouragingly, SSEN have set out governance changes to support the new vulnerability strategy, including new role requirements.

SSEN's energy transition proposals have also changed and become clearer since the first draft. They have doubled the size of their proposed 'shareholder financed' fund to £500k p.a. (or £2.5m across ED2) and say they will now be focused on supporting communities rather than individuals. They limit its explanation for this change of strategic focus by saying that it was prompted by stakeholder feedback. They anticipate that the fund will receive bids from local authorities, parish councils and local heat groups to help fund the 'installation of LCTs (such as smart heating controls), EV schemes and additional support for energy efficiency measures'. The plan also describes a number of educational initiatives – helping to prepare school children for the energy transition, and helping individuals in fuel poverty (via 'community hubs') with money management and energy efficiency steps. SSEN estimate the possible reach and financial value of these various activities, but having a rigorous programme in place to understand their real-world impact (ideally on a trial basis initially) will be important in order to identify the best, and to ensure they are delivering value for money (even when the costs are shareholder-funded).

Costs are transparently set out in the strategy and broken down by activity. As with other DNOs, this scaling up of activity is driving significant additional costs – £12.3m in SSEN's case (or £14.8m including its shareholder fund) compared with c.£4m in ED1.

In addition, SSEN have proposed a CVP of 'tailored' resilience plans for PSR customers. This is further discussed in SSEN's CVP section.

### 6.4 (iii) Reliability

Among the DNOs, SSEN have had the worst reliability performance in ED1 and their plan says that they are targeting a reduction of 20% in both the number of power cuts and the number of minutes that customers spend without power. They told us that these reduction percentages reflect a comparison of their forecast performance at the end of ED2 with Ofgem's original IIS targets for SSEN at the end of ED1. Table 88 below – which compares SSEN's average actual performance in ED1 with its forecast average performance in ED2 – suggests that, across their two networks, SSEN's proposals could lead to a reduction of 5-10% for the number of power cuts, and roughly a 30% reduction in the overall time that customers spend without power. SSEN say that their plan currently includes all the investments that are supported by a robust CBA and that, if they have to go further to meet the eventual targets that Ofgem sets, they would be making investments that 'exceed their value to consumers'. Ofgem will need to weigh this up when setting final IIS targets. In terms of worst-served customers, SSEN are planning to reduce the number of customers who meet the WSC criteria by 75% at a cost of £25.2m (c.87% of which will be spent on their Scottish network).

*Table 88: SSEN's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with SSEN's performance in ED1.*

| | ED2 Average | | | | % change from ED1 Average | | | |
|---|---|---|---|---|---|---|---|---|
| | CI | CML | CI | CML | CI | CML | CI | CML |
| SSES | 49 | 34 | 46 | 30 | -8% | -26% | -9% | -29% |
| SSEH | 65 | 41 | 59 | 32 | -5% | -29% | -5% | -34% |

## 6.5 Consumer Value Propositions

*CVP1: Embedded Whole System Support For Local Authorities – not recommended*

Through this CVP, SSEN would provide embedded support and resource to enable 72 Local Authorities and up to 200 Community Groups to optimise their use of the electricity network and plan whole system opportunities. The cost of this proposal is £12.3m (not in baseline), primarily FTEs, and the estimated net benefits are £11.2m, primarily through earlier delivery of projects.

The Challenge Group acknowledges that Local Authorities and Community Groups are likely to see value in the provision of this service. But we are also concerned that, as structured, the resources provided to Local Authorities, which will effectively be free of charge, may not be used most efficiently and effectively; it may be overly aligned with the network interests of DNOs, rather than considering non-network solutions. We are not convinced that SSEN have the capability to deliver these services.

Furthermore, we consider that such proactive Local Authority engagement should be a business-as-usual activity as other DNOs are planning. For example, the following diagram is taken from UKPN's Local Area Energy Planning Framework appendix to their business plan, which is included in their baseline plan. We consider that this represents an appropriate balance for DNO engagement to deliver whole system solutions with Local Authorities and other local groups. The proposed 'Middle Ground' option described below would appear to still offer a proactive approach without the risk of DNO network solutions dominating.

| | DNO Light Touch | Middle Ground | DNO Driven |
|---|---|---|---|
| Mode of engagement | *Purely reactive responding to connection request*<br>***May drive unnecessary delays*** | *Collaborative engagement with pre-agreed criteria & format* | *Network pro-actively drives local planning*<br>***Risks not being aligned to the needs of local stakeholders & customers*** |
| Level of detail | *Conduct only high level assessments of plans*<br>***May result in regret spend*** | *Ensure minimum confidence is met across key criteria & account for differing confidence levels* | *Require full cross vector energy system modelling & least worst regrets assessment*<br>***Would require additional resource & time*** |

What we are aiming for

*CVP2: Supporting Broadband to Island Communities – not recommended*

The key aim of the CVP is to utilise fibre optic cores in subsea cables to ensure that remote communities have access to the benefits arising from better connectivity. SSEN have forecasted that this CVP could provide this additional service to up to 14 remote island communities in ED2. The cost of this proposal is £8.0m, primarily for additional fibre connection from the beach to the local community, and the estimated net benefits are £27m, primarily through the avoided costs of laying separate fibreoptic cables and the additional value of a high-speed connection.

As the Challenge Group understands this proposal, SSEN will deliver this functionality in its subsea cables regardless of the CVP. However, this only provides the connectivity up to the cable 'beaching' point and island electrical network connection point. For some islands this may be close to population centres or existing 'local' communications networks. Whereas in some locations this beaching point may be a significant distance away and could need additional infrastructure to provide a more 'local' connection point. We recognise the additional value delivered to these island communities and the opportunities to do so at a lower 'whole system' cost. However, we question whether the additional costs of providing fibreoptic cables from the subsea cable termination to the broadband network should be borne by electricity consumers, and whether a commercial solution with third parties has been fully explored.

*CVP3: Seagrass meadow planting – partial support*

The CVP proposal to fund seagrass planting is an interesting mitigation measure reflecting the island communities which SSEN serve and the potential for subsea cables to cause damage to the seabed. It aims to improve biodiversity in locations close to SSEN subsea cables by supporting restoration of up to 17 hectares of seagrass beds where this has not already been initiated as part of marine conservation. This should decrease coastal erosion, help to protect coastal areas from storm damage, improve water quality and sea life diversity whilst reducing carbon in the atmosphere. The estimated cost of £2.6m would deliver estimated net benefits of £3.4m from carbon sequestration, water quality improvement, improvements to fishing stocks and biodiversity net gain.

SSEN are aware of the significant risks associated with deliverability. Their proposal would lead to a very significant increase in seagrass planting in the UK, and the costs-benefit of this activity are still uncertain. However, they note that investment at this stage will help to mainstream and de-risk what is potentially both a very important source of carbon sequestration and a major contributor to water quality. The proposal identifies areas for planting across both licence areas so that benefits should flow to consumers across the licensed area.

The Challenge Group considers that this initiative could bring substantial benefits in marine biodiversity, carbon storage and indeed coastal climate resilience. However, we also recognise that there are significant risks associated with deliverability, including cost, which would have a significant impact on the benefits. We would support a reward subject to it being possible to establish a reasonably robust benefit calculation.

*CVP4: Energy Efficiency Accelerator and Community Flexibility Market – not recommended*

Under this CVP, SSEN propose to work with Local Authorities, community groups and local partners to deliver specific energy efficiency interventions, providing a reduction in baseline and peak demands on the electricity network and delivering benefits in alleviating fuel poverty and quality of living for customers. The investment required to deliver this CVP will be set initially at £20m, which will be utilised in projects that have a demonstrable benefit to the network in terms of reducing demand or slowing demand growth.

The Challenge Group welcomes the further development of research and trials completed in ED1 and the application of the learning from these to the proposals in the CVP for ED2. We recognise the difficulties in engaging customers in energy efficiency measures and see merit in the approach proposed by SSEN. We note that the significant benefits arising from these energy efficiency measures are societal and relate to the quality of living. We also recognise the merits of engaging local Community Energy Groups to increase their awareness of the opportunities and commercial benefits of flexibility services. However, we question whether this goes significantly beyond what might be expected of a proactive DSO. Whilst noting the opportunity to save some FTE resource in delivering these initiatives, we are not convinced of the need to combine these two CVPs.

*CVP5: Personal resilience plans – partial support*

Under this CVP, SSEN will offer 420,000 PSR customers a 'tailored' personal resilience plan to help them prepare for, and understand what to do in the case of, a power cut. It also proposes to fund the provision of back-up battery packs for 21,000 priority customers. It is estimated to cost £7.3m and to bring a net value of £3.9m.

This type of support is clearly relevant for a DNO – and we agree with the principle that personalisation and proactivity can transform the impact of traditional activities. However, it was unclear to us how tailored the information in the plans would be given that the majority of the cost was associated with funding the battery packs.

In response to our challenge about what evidence SSEN have of the likely effectiveness of this approach, they have now clarified that they know from experience that a reactive approach to providing battery packs has sometimes led to shortages and delays. They say that they have also now conducted limited field tests of the battery packs with customers with a range of different needs (including feeding machines, heart monitors and TeleCare alarms). This is a positive response. A significant portion of the value of this CVP is associated with reducing people's stress and helping them feel in control. So it would be important for SSEN to conduct some early tests before rolling out to understand the impact the plans have on consumers in practice, and how to deliver the positive benefits promised in the assumptions.

We give this proposal our qualified support, although Ofgem will need to satisfy itself that it is sufficiently different from activities that other DNOs are planning to provide as part of their mainstream vulnerability activities, in order to justify it being rewarded as a CVP.

## 6.6 Finance

We think it unfortunate that, despite the fact that we made a number of suggestions in relation to SSEN's draft plan, the company have elected not to deal with matters relating to financing in their Supporting Paper 9, which in other areas provides a helpful track of changes between the draft and the BP. Although not all of an entirely satisfactory nature, the financing section of the BP does, in fact, show some improvements over the draft.

SSEN continue to target a rating of BBB+/Baa1 in the base case for both the Notional and Actual Companies. SSEN describe this as 'Ofgem's target rating' which we find unhelpful: Ofgem is clear that it considers it is for individual DNOs to determine their target ratings. We accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status, but we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. We regard BBB+/Baa1 as at the upper end of the acceptable target range and certainly do not consider that a company needs to demonstrate an expectation of that rating in order to be deemed 'financeable'.

Because SSEN reject some of Ofgem's W/As, describing them (unnecessarily provocatively in our view) as 'errors', the presentation of the output from the stress testing which it has carried out is very unclear. Ofgem's W/As include the OW of 25 basis points, producing an overall equivalent cost of equity allowance of 4.65%. There is also a requirement to model 25% index-linked debt in the Notional Company. Because of SSEN's rejection of the OW assumption, some of their base case modelling appears to have been carried out with a cost of equity allowance of 4.4% – although presentation is unclear. The results show both the SEPD and the SHEPD Notional Companies under a certain amount of stress in the downside cases (particularly the minus 2% RoRE sensitivity) but not unfinanceable. Both Actual Companies are clearly financeable, with SEPD likely to retain its BBB+/Baa1 rating and SHEPD projected to do so comfortably.

We made clear to SSEN that we did not consider the cost of equity allowance of 6.75% proposed in their draft plan as in the best interests of consumers. We are pleased to note that SSEN have reduced the level of their proposal and have now presented analysis based on a 5.9% cost of equity allowance, albeit with a statement that they require an allowance of 'at least . . .6.3%'. We assume from the results and the preamble to the tables that the results for the Actual Companies shown in tables 15 and 16, 19, 22 and 25 (SEPD and SHEPD) are based on a cost of equity allowance of 5.9% (though it would have been better if this had been made a good deal clearer: these are key results and transparency and ease of analysis is important). As indicated above, we do not, in any case, consider a cost of equity allowance at this level is necessary for SSEN to achieve financeability.

We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions, but note here a point made specifically (though not exclusively) by SSEN: that they regard the relatively high proportion of expenditure in ED2 likely to be covered by uncertainty mechanisms as heightening the risk profile of the Price Control (PC) because of concerns that such expenditure will be 'disallowed' or remunerated at 'lower than proposed cost allowances'. SSEN argue that this puts upward pressure on the required cost of equity allowance. We agree that it is important UMs are clearly defined and both effectively and promptly administered, but do not consider that there is any reason why properly proposed expenditure should be disallowed or remunerated at any rate other than that agreed in the PC. Overall, we have always been clear that, although UMs do result in an element of uncertainty as to the total financing which will be required, on balance, we regard the greater dependence on UMs in this price control as reducing risk rather than the reverse.

SSEN's analysis has been based on 60% gearing, the 'natural' capitalisation rate and depreciation over 45 years (although it makes the point that it may wish to change this at the Final Determination stage). There is a certain amount of evidence that it has given at least some consideration to the potential to improve financeability through analysis of the 'levers' for the improvement of financeability set out by Ofgem in the SSMD such as alternative rates of gearing, depreciation and capitalisation (in the context of which there is a specific adjustment in relation to the Shetland Link). However, we are not clear that these 'levers', particularly in relation to gearing and dividend holidays or new equity, have been exhaustively examined. In any event, we can see no rationale for the company's statement that they may wish to reconsider the depreciation period at the FD stage.

SSEN have modelled on the basis of Ofgem's cost of debt W/A. As noted in our commentary on the company's draft plan, it is for individual DNOs to determine their debt funding strategies and the extent to which they implement those strategies on a group-wide basis, but we can see no reason for a small company premium in relation to any part of the SSEN group.

SSEN's BP contains the statement (repeated in the Business Plan Assurance Annex S7) that the Board is satisfied that 'the licensee is technically financeable on both a notional and actual capital structure'. The BP goes on to make points about the appropriateness of Ofgem's cost of equity W/A and its assumption in relation to the proportion of index-linked debt in the Notional Company, but does not give any clear explanation for the inclusion of the word 'technically'. It is our view, expressed above, that the company are in a position to make an unambiguous statement about the financeability of their BP without the inclusion of that modifier. That is particularly so if we are correct in our understanding that the results of the stress testing shown in the plan are based on analysis with a cost of equity allowance of 4.4%.

# 6. Company report – UKPN

As a summary, we have assigned UKPN's Business Plan the following ratings:

*Table 89: UKPN BP scores*[19]

| | |
|---|---|
| Track record from RIIO-ED1 | 4 |
| Scenarios and forecasts | 3 |
| Totex: LRE, incl. anticipatory investment | 4 |
| Totex: NLRE, incl. asset health | 2 |
| Totex: Network operating costs | 5 |
| Totex: Non-operational costs | 3 |
| Totex: Ongoing efficiency and RPE | 4 |
| Totex: Uncertainty mechanisms | 4 |
| Outputs: DSO and digitalisation strategy | 5 |
| Outputs: Whole system strategy | 4 |
| Outputs: EAP | 4 |
| Outputs: Vulnerability strategy | 4 |
| Outputs: Reliability | 4 |
| Finance | 4 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of UKPN's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 70% from ED1 levels and we are concerned that this may not include benefits from network capacity optimisation.
- **DSO and whole system –** UKPN are targeting annual flexibility actions of 732MW, delivering benefits of £601m over ED2. We are concerned that these benefits may not be realised and that they are not reflected in load-related capex forecasts.
- **Costs –** Baseline totex has increased by £360m since the draft plan and is forecast to increase by 18% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that underlying cost increases for the same asset basis are unjustified.
- **Risks and uncertainty –** UKPN have proposed load-related uncertainty mechanisms which could add £747m or 16% of totex. We are concerned that this is a wider than necessary range and that some of these costs may already be included in baseline expenditure.
- **Vulnerability –** UKPN's costs for delivering fuel poverty support appear to be high compared with other DNOs' costs for similar activities. We would like to see UKPN provide evidence that these costs are efficient.
- **Finance –** UKPN's plan is very clearly financeable on the basis of Ofgem's Working Assumptions (W/As) for the cost of capital and it includes a helpfully clear statement to that effect. We consider it a pity, however that, whatever UKPN's reservations about some

[19] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

of Ofgem's 'levers' to improve financeability, they have not fully explored all of them, including gearing and dividend restraint or new equity, which we consider could well result in the BP being financeable with a cost of equity allowance below 4.65% (to the benefit of UKPN's customers).

## 7.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

Key performance measures are shown in the tables below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 90: UKPN ED1 performance summary*

| ED1 performance (2021 RRP) | UKPN |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 1.9% |
| Customer service (BMCS) | 0.6% |
| Time to connect (TTC) | 0.1% |
| **Output incentives total** | 2.6% |
| | |
| **Totex efficiency incentives** | 1.1% |
| **Operational RoRE** | 9.2% |

**ED1 - Totex (2021 PCFM)**

| £m (2012/13 prices) | UKPN |
|---|---|
| Totex allowance | 6038 |
| Totex actual/forecast | 5419 |
| % totex (under)/overspend | (10%) |
| % LRE (under)/over spend | (44%) |
| % Totex (excl. LRE) (under)/overspend | (3%) |

Overall, we note that UKPN expect their ED1 outturn to underspend their allowance by 10%. They are showing an underspend of 44% in load-related capex, largely attributable to lower-than-expected LCT growth. Once load-related capex is excluded, overall outturn totex expenditure is expected to be 3% lower than the allowance.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) performance is amongst the highest of all DNOs and the customer service incentive (BMCS) is also amongst the highest.

## 7.2 Costs, scenarios and forecasts

### 7.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios that UKPN has examined and note UKPN's LRE strategy aligns most closely to the Consumer Transformation scenario in the DFES. We welcome that these scenarios appear to be consistent with Net Zero targets.

By the end of ED2, UKPN forecast they will have connected:

- 2,637k EVs and 278k heat pumps under their Consumer Transformation (Best View) scenario; and,
- 2,729k EVs and 612k heat pumps under their Upper View scenario.

These scenarios are presented below as 'Best View' and 'Upper View'.

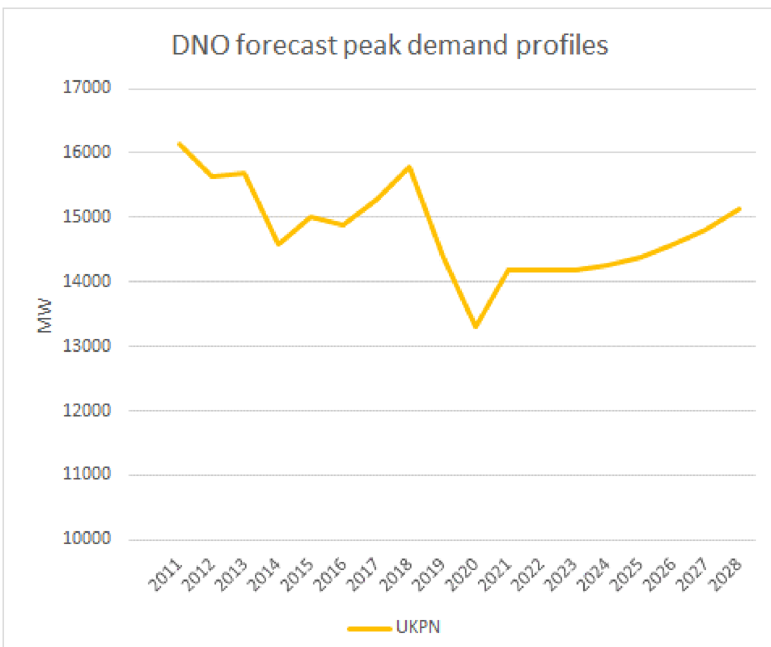
*Table 91: UKPN low-carbon technology scenarios*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| UKPN | 2637 | 30% | 278 | 3% | 2729 | 31% | 612 | 7% |

UKPN have around 28% of the networks' total customer base. The forecast number of EVs in the Best View scenario across this customer base in 2028 is broadly in line with the ESO 2021 FES Consumer Transformation or Leading The Way scenarios, which forecast around 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers. The forecast number of heat pumps appears to be well below the national average, but we note that UKPN is forecasting that heat networks would likely be deployed in its area instead.

The UKPN submission of demand profiles in the BPDTs (shown below) shows an increase of around 14% between 2020 and 2028, which is above the equivalent peak demand increase of 11% forecast in the ESO 2021 'Consumer Transformation' scenario. However, we note the Covid related decrease in the 2020 figures which may account for this higher increase.

*Chart 31: UKPN forecast peak demand profile*




Overall, we consider that UKPN have undertaken effective scenario planning, noting that lower than expected heat pump forecasts in the Best View are expected to be due to the development of heat networks.

### 7.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered; and,
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages.

The UKPN ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £4,833m and is a 17% increase on the annual average expenditure rate during ED1. We are disappointed that the bid has increased by around £400m from the figure submitted in the UKPN draft plan. The following table compares the UKPN cost submissions between ED1 actuals/forecasts and ED2 forecasts. It also compares the draft and final plans[20].

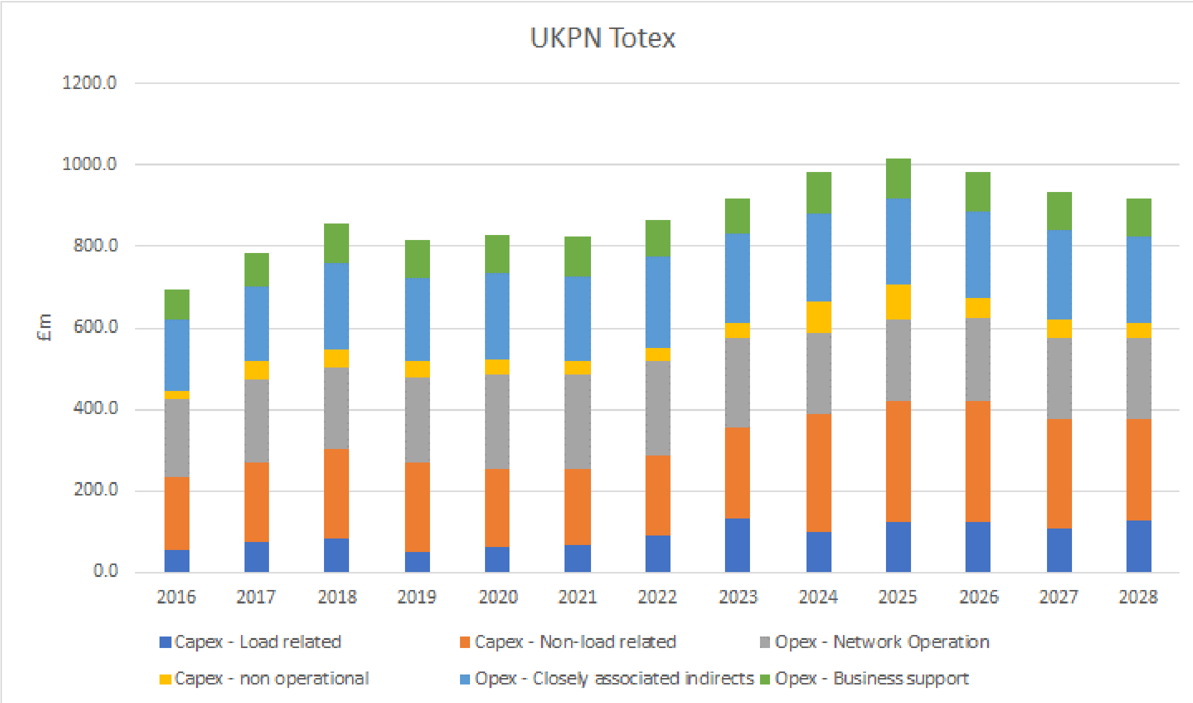
*Table 92: UKPN overall totex comparison*

| UKPN | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| Overall | ED1 | ED2 | ED1 | ED2 | ED1-ED2 | ED1 | ED2 | ED1 | ED2 | ED1-ED2 |
| Capex - Load related | 615.4 | 582.9 | 76.9 | 116.6 | 52% | 555.5 | 526.6 | 69.4 | 105.3 | 52% |
| Capex - Non-load related | 1610.5 | 1396.0 | 201.3 | 279.2 | 39% | 1599.2 | 1136.7 | 199.9 | 227.3 | 14% |
| Opex - Network Operation | 1713.1 | 1006.1 | 214.1 | 201.2 | -6% | 1699.7 | 997.3 | 212.5 | 199.5 | -6% |
| Capex - non operational | 294.9 | 292.4 | 36.9 | 58.5 | 59% | 294.8 | 290.9 | 36.9 | 58.2 | 58% |
| Opex - Closely associated indirects | 1640.6 | 1073.4 | 205.1 | 214.7 | 5% | 1642.9 | 1023.7 | 205.4 | 204.7 | 0% |
| Opex - Business support | 714.0 | 482.5 | 89.3 | 96.5 | 8% | 713.2 | 463.7 | 89.1 | 92.7 | 4% |
| **BPDT Totex** | 6588.4 | 4833.4 | 823.6 | 966.7 | 17% | 6505.2 | 4438.9 | 813.2 | 887.8 | 9% |
| **Baseline totex after OE/RPE adjustments** | | | 823.6 | 967.4 | 17% | | | | | |

A profile of the totex and main expenditure categories is shown in the next chart, showing a significant increase at the start of ED2 in non-load capex.

[20] Note: These totex figures exclude 'other costs outside the price control' The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.

*Chart 32: UKPN overall totex profile*




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for most ongoing expenditure, and we have scrutinised reasons for increases from these levels. Our assessments for these individual cost categories are set out below. We are seeking to understand the justifications for these potential increases.

### *ii.a. Totex: LRE*

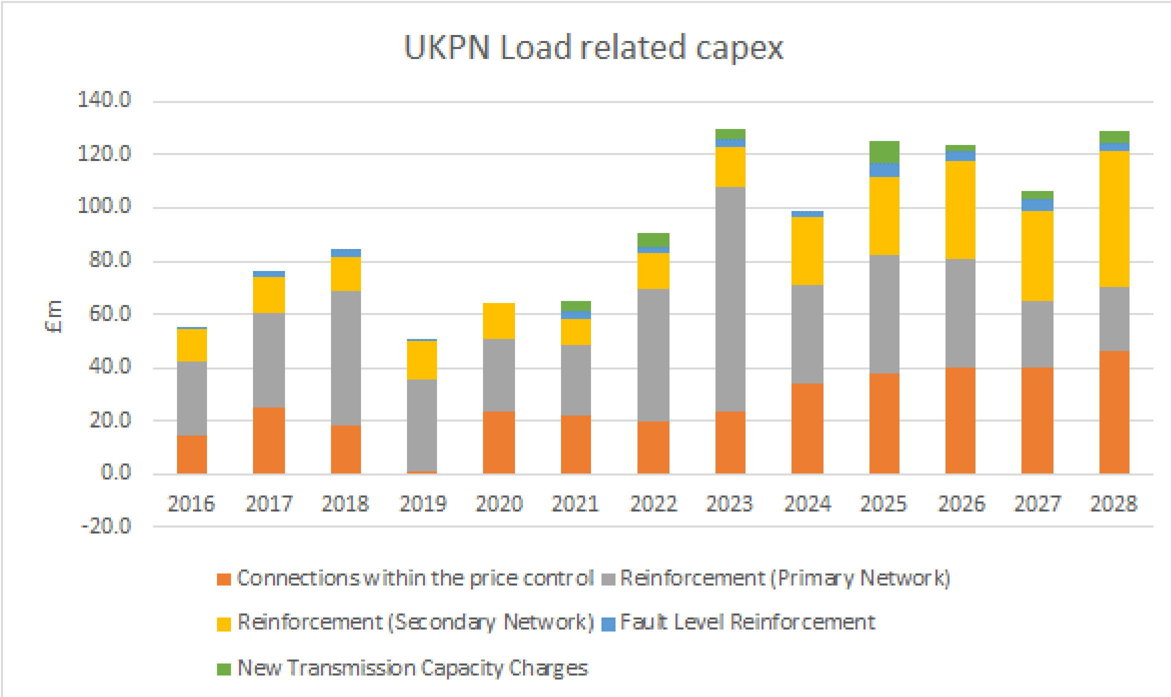
The UKPN bid for baseline LRE is £583m, which represents a 52% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual categories, with reinforcement relating to secondary networks and connections showing significant increases.

*Table 93: UKPN load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Connections within the price control | 147.9 | 198.7 | 18.5 | 39.7 | 115% |
| Reinforcement (Primary Network) | 335.5 | 170.5 | 41.9 | 34.1 | -19% |
| Reinforcement (Secondary Network) | 105.5 | 176.8 | 13.2 | 35.4 | 168% |
| Fault Level Reinforcement | 13.3 | 18.6 | 1.7 | 3.7 | 124% |
| New Transmission Capacity Charges | 13.3 | 18.3 | 1.7 | 3.7 | 120% |
| **Total load related costs** | 615.4 | 582.9 | 76.9 | 116.6 | 52% |

A profile of the LRE expenditure categories is shown, below. It shows a significant increase over the course of ED2, especially in secondary network reinforcement.

*Chart 33: UKPN load-related capex profile*




We consider that UKPN have provided reasonable justifications for increases in LRE, especially relating to the need to address anticipated LV network capacity constraints to connect low carbon technologies. However, we were concerned that UKPN's plan had not fully considered the availability of current capacity headroom, and the benefits from flexibility and smart control to enhance network utilisation. As such, the proposed baseline bid appears uncertain and may be overstated – a further proportion of this may be best addressed through uncertainty mechanisms.

We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

***ii.b. Totex: NLRE***

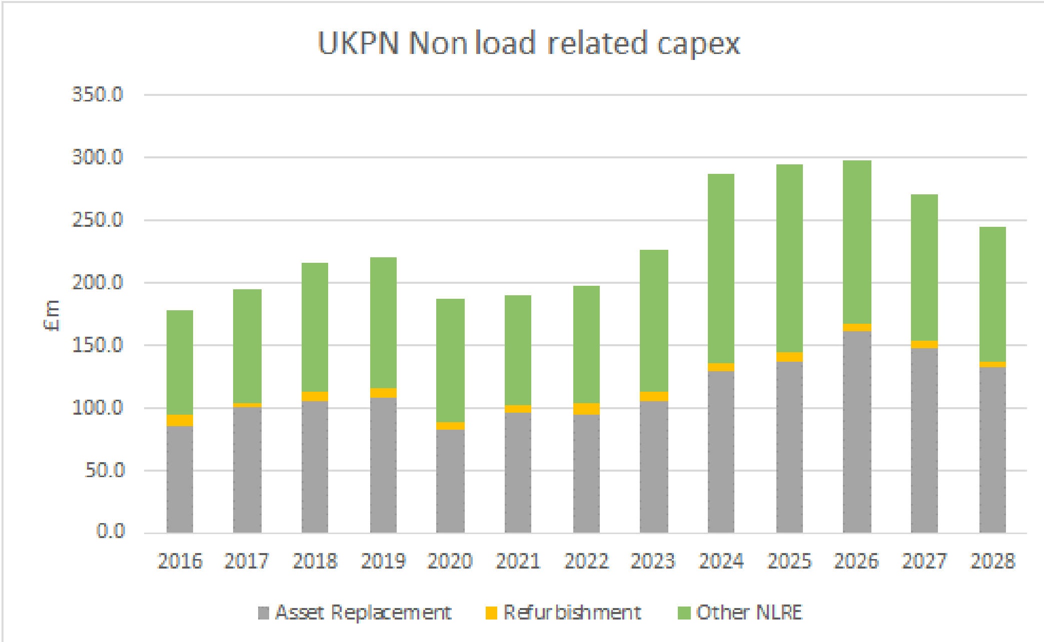
The UKPN bid for baseline NLRE is £1,396m, which represents a 39% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with reinforcement relating to asset replacement (61%), and operational IT and telecoms (134%) and environmental reporting/PCBs (185%) showing significant increases in particular.

*Table 94: UKPN non-load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Non Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Diversions (Excluding Rail Electrification) | 228.2 | 164.4 | 28.5 | 32.9 | 15% |
| Diversions Rail Elec | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| Asset Replacement | 780.5 | 707.5 | 97.6 | 141.5 | 45% |
| Refurbishment | 53.7 | 32.7 | 6.7 | 6.5 | -2% |
| Civil Works Condition Driven | 47.6 | 39.4 | 6.0 | 7.9 | 32% |
| Operational IT and telecoms | 150.5 | 220.0 | 18.8 | 44.0 | 134% |
| Blackstart | 23.5 | 0.0 | 2.9 | 0.0 | -100% |
| BT21CN | 40.0 | 0.0 | 5.0 | 0.0 | -100% |
| Legal & Safety | 85.9 | 54.8 | 10.7 | 11.0 | 2% |
| QoS & North of Scotland Resilience | 34.2 | 0.0 | 4.3 | 0.0 | -100% |
| Flood Mitigation | 7.1 | 17.1 | 0.9 | 3.4 | 286% |
| Physical Security | 0.2 | 0.0 | 0.0 | 0.0 | -100% |
| Rising and Lateral Mains | 6.5 | 5.8 | 0.8 | 1.2 | 44% |
| Overhead Line Clearances | 107.0 | 58.3 | 13.4 | 11.7 | -13% |
| Worst Served Customers | 7.5 | 28.0 | 0.9 | 5.6 | 496% |
| Environmental Reporting & Losses | 38.2 | 68.0 | 4.8 | 13.6 | 185% |
| HVP | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| **Total non load related capex** | 1610.5 | 1396.0 | 201.3 | 279.2 | 39% |

A profile of the NLRE expenditure categories from 2016 to 2028 is shown, below. It shows a significant decline at the end of ED1 before increasing at the start of ED2. We are concerned that the ED2 increase is due to high-cost asset replacement expenditure being deferred to ED2 and customers having to pay twice for the same replacement work. We note UKPN's proposal to increase investment in fluid filled cable replacement above historic levels by £90m during ED2 and suggest the need and cost of this is examined carefully by Ofgem.

*Chart 34: UKPN overall non-load capex profile*




We recognise that there are some upward cost drivers in relation to DSO and network visibility investment, and from accelerated PCB removal. However, we do not think the scale of NLRE expenditure increases for ED2 have been justified given the asset base remains largely the same as for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We note that UKPN are targeting a network risk target of 26%, resulting in a closing ED2 position of 4.6% above opening. The forecast monetised risk reduction is 41.0 pence per point. We note that UKPN are forecasting at the end of ED2 a network risk of 26% without intervention and a target after intervention of 4.6%. The forecast monetised risk reduction is 41.0 pence per point.

We welcome that UKPN are targeting a total network risk target of 4.6% for the end of ED2, but we do not believe the increase in asset replacement expenditure has been justified.

For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The UKPN profile is shown below.

*Table 95: Low voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| LPN | 0 | 0 | 0 | 0% | 0% |
| SPN | 914 | 1437 | 1735 | 57% | 21% |
| EPN | 2557 | 2847 | 5745 | 11% | 102% |
| TOTAL | 3471 | 4284 | 7480 | 23% | 75% |

We noted that the forecast number of LV poles subject to asset replacement during ED2 is significantly greater than ED1 and we have examined their EJP in more detail.

We note that the preferred option in the EJP is to carry out an enhanced ED2 strategy. This strategy will deliver the replacement of 70,200 poles (LV and HV) across the ED2 period. The enhanced replacement programme would see the addition of a pole saver to each new pole. In addition to these, the volume of replacements increased due to the ageing of the overhead line network, improving the Asset Health Index by the end of ED2.

The EJP states that this investment is needed in the overhead network to ensure current network performance and customer safety standards can be met. We acknowledge that the age of wood poles in increasing and an increase in the rate of replacement may be required. But little evidence is provided on expected failure rates of these poles and its impact on consumers to support the requirement for this enhanced replacement strategy and the proposed increases in number of poles to be replaced. We ask Ofgem to carefully examine this increased pole replacement programme to ensure that it delivers value for money for consumers.

### *ii.c. Totex: Network operating costs*

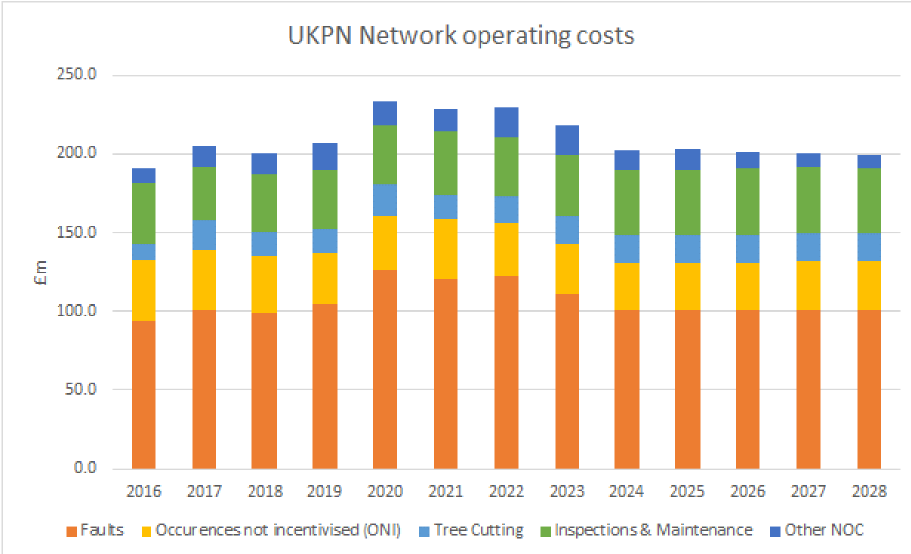
The UKPN bid for network operating costs is £1,006m, which represents a 6% decrease from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 96: UKPN network operating cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Opex - Network Operating Costs** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Faults | 877.0 | 502.9 | 109.6 | 100.6 | -8% |
| Severe Weather 1 in 20 | 2.3 | 9.3 | 0.3 | 1.9 | 540% |
| ONIs | 285.6 | 151.7 | 35.7 | 30.3 | -15% |
| Tree Cutting | 129.2 | 89.8 | 16.2 | 18.0 | 11% |
| I&M | 300.0 | 209.1 | 37.5 | 41.8 | 11% |
| NOCs Other | 53.4 | 33.4 | 6.7 | 6.7 | 0% |
| Smart Meters | 65.4 | 9.9 | 8.2 | 2.0 | -76% |
| **Total Network Operating Costs** | 1713.1 | 1006.1 | 214.1 | 201.2 | -6% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown, below. The profile increases over the first two years of the ED2 period.

*Chart 35: UKPN overall network operating cost profile*




Overall, we consider that UKPN have provided reasonable justifications in respect of these costs. We welcome the fact that UKPN have been able to propose a decrease in these costs while still maintaining good reliability targets.

### *ii.d. Totex: Non-operational costs*

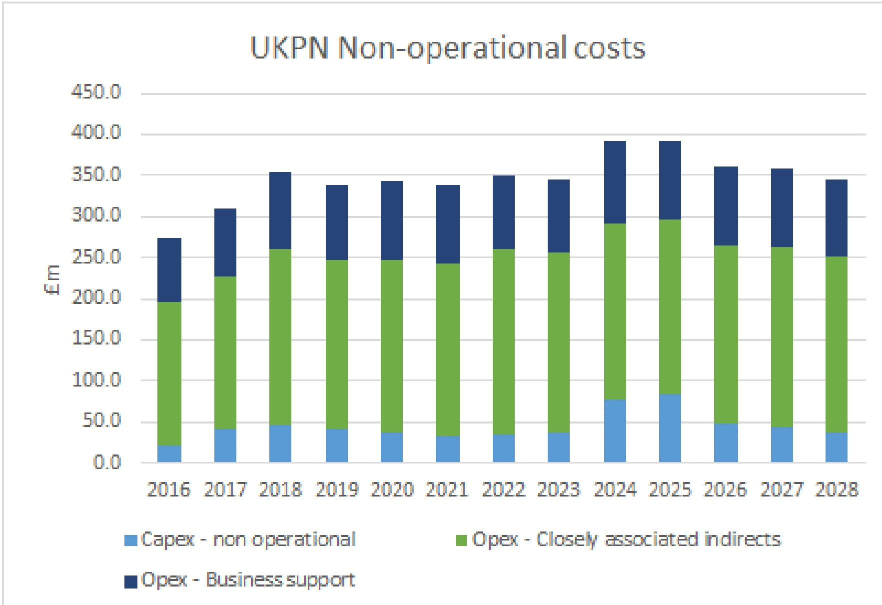
Under this cost grouping, we have included business support, closely associated indirects and non-operational capex. The UKPN bid is for £482m of business support costs (an increase of 8%), £1,073m of closely associated indirects (an increase of 5%), and £292m of non-operational capex (an increase of 59%). The combined increase is 12% which is the lowest of all DNOs, but an increase from the 7% proposed in UKPN's draft plan. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 97: UKPN non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 390.1 | 265.8 | 48.8 | 53.2 | 9% |
| IT& Telecoms (Business Support) | 227.2 | 175.8 | 28.4 | 35.2 | 24% |
| Property Mgt | 96.7 | 41.0 | 12.1 | 8.2 | -32% |
| **Total Business Support Costs** | 714.0 | 482.5 | 89.3 | 96.5 | 8% |
| **Closely associated indirects** | | | | | |
| Core CAI | 1294.9 | 821.0 | 161.9 | 164.2 | 1% |
| Wayleaves | 103.1 | 86.2 | 12.9 | 17.2 | 34% |
| Operational Training (CAI) | 104.1 | 88.0 | 13.0 | 17.6 | 35% |
| Vehicles and Transport (CAI) | 138.5 | 78.2 | 17.3 | 15.6 | -10% |
| **Total CAI** | 1640.6 | 1073.4 | 205.1 | 214.7 | 5% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 157.3 | 166.4 | 19.7 | 33.3 | 69% |
| Property (Non-Op) | 32.2 | 34.8 | 4.0 | 7.0 | 73% |
| Vehicles and Transport (Non-Op) | 59.4 | 58.4 | 7.4 | 11.7 | 57% |
| Small Tools and Equipment | 46.0 | 32.7 | 5.7 | 6.5 | 14% |
| **Total non-op capex** | 294.9 | 292.4 | 36.9 | 58.5 | 59% |

A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown below. The profile shows a sharp increase at the start of the ED2 period and declines thereafter.

*Chart 36: UKPN overall non-operational cost profile*




UKPN provide limited evidence to justify these increases in their business plan, particularly the increases between draft and final. While the 12% increase in this overall area is the lowest of the DNO bids, we are concerned that some cost increases may be overstated and that efficiency opportunities have not been sought with corresponding rigour.

### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. UKPN have proposed a 1% annual efficiency challenge. As shown, below, the corresponding forecasts in business plan data tables indicate an overall ED2 saving of 4.8%. UKPN are forecasting real price effects over ED2 that total 4.8%.

*Table 98: UKPN Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| UKPN | 231 | 4.8% | 233 | 4.8% | 4833 |

UKPN's RPE forecasts are amongst the lowest of the DNOs and OE is amongst the highest. However, we suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 7.2 (iii) Uncertainty mechanisms

UKPN have significantly reduced their proposed bespoke uncertainty mechanisms since the draft plan which we welcome. The measures proposed are described in the table below.

*Table 99: UKPN UMs*

| Category | Risk addressed | Potential cost |
|---|---|---|
| Load-related expenditure, including unlooping/fuses and connections | Uncertain load-related expenditure | £131m |
| Load-related expenditure – capacity driver | Uncertain load-related expenditure | £333m |
| Load-related expenditure – primary infrastructure | Uncertain load-related expenditure | £283m |
| Diversions | Uncertain non-load expenditure | £181m |
| Total | | £928m |

The total of £928m represents 19% of their bid totex and the load-related element represents 16% of their bid totex.

We agree that a LRE uncertainty mechanism is necessary, or it could lead to consumers either bearing the cost of additional LRE expenditure which turns out not to be needed or providing a windfall gain from underspend. However, we are concerned with the potentially large proportion of UKPN's price control that may be covered by this mechanism and would suggest that this may be too wide a range for an effectively calibrated, value for money automatic mechanism to be confidently established.

## 7.3 DSO and whole system

### 7.3 (i) DSO and digitalisation strategy

UKPN are proposing to spend £224m on DSO activities in ED2 (an increase compared to the draft plan forecast of £139m) and are targeting 22% of secondary substations to have metering installed. UKPN are proposing that 732MW of demand (or 5% of peak demand) will be met through flexibility services. UKPN are proposing that their DSO activity will have 162 staff by 2028.

The specific DSO activities that UKPN are planning to undertake include:

- **Planning & network development –** this will include enhancing DFES with greater granularity and accuracy, with 22% of LV underground network monitored in real time by end ED2. 2200 LV substations, where constraints will occur during ED2, will have real-time physical monitoring. Analytics will model 100% of the network. A new investment planning process will be established to enable independent decisions on investment. They will prioritise a flexibility first approach.
- **Network operation –** including: visibility of LV network from 16 to 26%; publishing a forward view of constraints; operational performance of DER; interaction with ESO API interface; a dispatch of flexibility units; and, operational planning.

- **Market development –** including: publishing operability framework; providing product/service requirements; creating more real-time markets; and, including stakeholder feedback through the advisory board.
- UKPN propose setting up a legally separable DSO business unit and supervisory board with a DSO:DNO code to provide transparency and build trust.

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table 100: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| UKPN | 15,138 | 1822 | 732 | 5% | 40% | 601 |

DSO benefits during ED2 are calculated by UKPN as being £601m, comprising:

- £410m of capital investment on the primary and secondary network, enabled by making greater use of flexibility;
- £185m of capital investment to facilitate distributed energy, enabled through the use of innovative flexible connections; and,
- £6m of additional secondary reinforcement through the use of enhanced modelling and data analytics to inform investment decisions.

UKPN state that the DSO investments will allow investment to be deferred and avoided until 2040. They have assessed with the ESO that £170m of ESO-related benefits will flow from the DSO strategy during ED2. These come from expanding Regional Development Programmes, providing timely network access for DER and coordinating system operation across the T-D boundary. These ESO-related benefits may deliver £470-580m of benefits out to 2040.

UKPN estimate that their DSO strategy will deliver an NPV benefit of £560-670m out to 2040. In addition, they have worked with the Carbon Trust and Imperial College using their recent analysis “Flexibility in GB”[21] to understand how much of the £9.6-16.7bn of flexibility benefits in 2050 could be attributed to UK Power Networks’ DSO. They estimate this to be between £230m and £2.0bn out to 2040, which could increase the total NPV to between £780m to £2.6bn out to 2040.

Overall, the UKPN DSO strategy and action plan seems well thought out and deliverable, offering significant consumer benefits. It provides a rationale for the choices made and seeks to justify the levels of cost benefits that might accrue. UKPN sees the role of the DSO as going beyond flexibility, has clearly identified potential benefits, and appears the most ambitious of the DSO plans. However, it will be important that the establishment of a legally separate DSO and associated governance does not, in itself, create market barriers to the development of flexibility markets by adding complexity and cost that may deter third parties.

[21] The full report can be found here.

***Digitalisation***

The UKPN digitalisation plan is well constructed, providing confidence about deliverability and integration with the DSO vision. The plan aims to deliver benefits to customers, employees, assets and operations, and smart networks and DSO through the following action areas:

- IT to support day to day business operations (£48m);
- Modern application architecture (£66m);
- DSO data capability (£29m); and,
- Employee, customer and asset solutions (£22m).

Overall, the digitalisation strategy appears to be well developed in response to customer and stakeholder engagement and supports the DSO strategy with clear delivery plans. There is a focus on open data principles to enable third-party access.

### 7.3 (ii) Whole system strategy

The UKPN plan outlines four main building blocks where whole system initiatives are planned. These are in addition to the whole electricity system benefits described in the DSO actions.

- **Whole electricity –** outreach initiatives include partnering with the ESO to deliver benefits including the expansion of Regional Development Plans, increased interaction with LAs, and promotion of demand-side participation.
- **Whole transport –** collaborate with LAs to roll out EV charging infrastructure, promote Vehicle to Grid and smart charging, and provide free fuse upgrades to enhance LCT uptake.
- **Whole heat –** build evidence to support LA decarbonisation plans, provide guidance to customers on heat electrification options; use one-touch upgrades to prepare for both EVs and heat pumps when LCT connections are requested.
- **Whole system planning –** engage with 127 regional and local planning authorities on their climate plans; by 2024, provide them with planning tools; include whole system solutions in investment decisions and provide digital outage planning information to Distributed Energy Resources.

UKPN have developed a set of performance measures and benefit targets for their whole system plan which is welcome. Overall, the plan appears to show a well-thought-out set of strategies and action plans that should deliver tangible benefits. However, the whole system plan seems to mainly focus on electricity connection related activities and the interactions for heat and transport may not fully consider the use of flexibility or non-network solutions.

## 7.4 Other outputs

### 7.4 (i) Environmental Action Plan

UKPN's EAP contains a very clear articulation of their vision strategy and actions. It draws out understanding of best practice and makes clear and meaningful links to the UN SDGs.

UKPN responded to our challenge to their draft plan both in some of the actions/targets but also by making clear the impact of actions.

In relation to its SBT and target for reduction of BCF, they have responded to challenge from CG and other stakeholders by committing to an early review of their SBT (which was set on a well below 2°C trajectory). They have adopted ambitious targets for BCF reduction (scopes 1, 2 and 3) and set out a clear set of costed actions to achieve reductions.

UKPN has chosen to retain a target of Net Zero by the end of 2028 with offsetting. The focus should be on carbon reduction to achieve short-term and mid-term targets and only seeking to achieve Net Zero through the use of offsetting as a last step when all practical reductions have been accomplished. The use of Net Zero should be clear and consistent to avoid confusion between the various carbon reduction targets. We also have reservations about the appropriateness of asking customers to fund offsetting.

UKPN's thinking in relation to carbon abatement schemes seems to be less developed than some other DNOs. On balance we think there is a case for a moderate amount to be spent on carbon abatement schemes given that these will be needed to achieve Net Zero in the longer term and that the proposals have stakeholder support. We strongly urge that emphasis is placed on developing nature-based and energy efficiency solutions, which would bring about other benefits for consumers and stakeholders within the supply area. We would urge this is to be the focus of any measures, rather than the goal of Net Zero by 2028.

On $SF_6$ UKPN have shown a very strong performance in leak detection and mitigation in ED1 and have the lowest target for leakage. In response to challenge, they are proposing significant investment of £6m in non-$SF_6$ replacement assets during ED2, which is a welcome step in the process of reducing bank.

The losses strategy is a CBA-driven approach to asset replacement combined with learning from e.g. SSEN Low Energy Automated Networks. There is a standard list of measures (cable and transformer size), plus a welcome commitment to use smart data. However, the target seems to us very unambitious and more explanation of why this is considered the right level would be appropriate.

**7.4 (ii) Vulnerability strategy**

UKPN's vulnerability strategy remains strong. It has a clear, practical vision – 'to maximise the value delivered to customers in vulnerable circumstances' – and is informed by sophisticated data analysis combined with extensive engagement. In it they set out a clear understanding of where they need to improve, despite a relatively strong performance in ED1, and their ED2 commitments would represent a significant step up in activity if they are delivered in line with the plan.

They aim to sign up c.86% of all customers eligible to be on its PSR, which appears to be one of the more stretching 'reach' targets set by the DNOs. They also commit to contact customers every 18 months to update details, which is more frequent than the 24-month minimum required by Ofgem and adopted by some other DNOs.

We welcome the fact that UKPN have formally ring-fenced 20% (or £5m) of their NIA to spend on projects that will benefit consumers in vulnerable circumstances, and will aim to achieve an extra £750k of funding value by working with co-funding partners.

At the heart of UKPN's strategy is an eye-catching commitment to fund an independent UK Power Networks Foundation to the tune of £4m a year, or £20m for the ED2 period.

Some £11m of this fund would be ear-marked to help avoid vulnerable customers being left behind by the energy transition. They estimate that this would support c.500k customers with either information and help, or by co-funding grants towards the installation of low-carbon technologies. The strategy sets out a number of ideas for the types of support that this might include, but we welcome the fact that solutions would ultimately be based on ‘transparent, competitive’ tenders from service providers and that they would be targeting those that ‘demonstrate the highest customer benefits and value for money’. They also acknowledge that UKPN may not ultimately be best placed to offer this type of information and advice and, importantly, they envision the possibility of handing this off to another party in the future.

The remaining £9m of the UKPN fund is to cover half the cost of their proposed fuel poverty programme. The programme as a whole promises to target 200k customers directly (by UKPN) with a further 300k supported through ‘regional collaboration’ programmes. They estimate that the programme would deliver some £67m of benefits by 2028. The assumptions underlying this calculation of value look reasonable and to be based where possible on savings that have actually been achieved by customers from similar types of intervention. However, we had concerns about some of the related assumptions that were set out in the CVP appendix. We took some reassurance, though, from the statement (also in their CVP appendix) that UKPN would ‘measure, quantify and externally verify’ value delivered on an annual basis. This should allow for on-going optimisation of the programme, as well as external assurance that real value of the scale promised is being delivered to customers in practice. Further detail on this CVP can be found in UKPN’s CVP section.

The full estimated £40m cost of delivering this vulnerability strategy appears to dwarf any other put forward by a DNO. Even ignoring the shareholder funded portion, the £20m cost that UKPN customers will fund is among the highest proposed. It is difficult for us to draw a direct comparison between costs and benefits offered by different plans for similar activities, but we note, for example, that the CVP element of UKPN’s fuel poverty programme (which is the customer-funded part) promises to deliver c.£13.5m of benefit (gross) in ED2 by helping 100k customers for a cost of £9m. By comparison, WPD promises £60m of value helping 113k fuel poor customers for a cost of £2m. Given that customers (including fuel poor customers) will pay for these activities, it is vital that Ofgem ensures that costs for broadly similar activities are efficient, and that there is a robust way to ensure that real-world benefits are actually delivered in the period.

As well as some helpful additional explanations, we identified a small number of material improvements in areas where we challenged the strategy in July. On their plan to update customer details in the PSR, they have introduced a new commitment to conduct ‘proactive data quality checks’ on all PSR records every 12 months. These checks will measure how complete each customer’s record is and UKPN will then seek to fill the gaps using additional data sources, including buying relevant data files if necessary. They have also split out the ‘shareholder’ funded portion of the fuel poverty programme from their CVP proposal which has the merit of not confusing ‘shareholder’ funding with financial rewards and cost recovery that are funded by customers.

### 7.4 (iii) Reliability

UKPN’s reliability plan, compared with the other DNOs, was the one that was most explicitly targeted on those customers who receive the worst reliability now. It also presented the broadest response to the range of reliability issues flagged in Ofgem’s methodology.

In terms of the core IIS measures of customer interruptions and customer minutes lost, UKPN propose the smallest improvement of all the plans. They justify this by saying that, from a willingness to pay point of view, more customers supported maintaining current levels rather than paying more for higher standards. However, if these proposals translate into the final targets set by Ofgem, it would mean that their customers in London would continue to experience the most reliable service of all DNOs, but their performance in other regions could be below average.

In terms of worst-served customers, they estimate that c.50k customers could meet this definition during ED2, and they commit to improve reliability 'by 25%' for as many customers as possible up to a total expenditure of £28m. We think the plan is unclear in terms of how many WSC they expect to have left by the end of the period, but UKPN did say in response to our challenge that they are aiming to improve performance for all customers who would fall into this category. We welcome the comment that they would also look at 'innovative solutions' to improve customer service where the cost of reinforcing the network in traditional ways is prohibitive. They say it will also reduce the number of 12-hour interruptions by a quarter in each of its regions.

UKPN were the only network to propose a target to reduce the number of short interruptions experienced by customers (by 10%), and to pay £25 compensation to customers who experience more than 25 short interruptions a year (although they do exclude those related to 'exceptional events' and those caused by any actions the company takes to avoid other interruptions). They also propose gathering and publishing more data on frequent, short power cuts, and 'Total Time not supplied' with the eventual aim of setting itself voluntary targets for these by the end of 2024.

*Table 101: UKPN's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with UKPN's performance in ED1.*

| | ED2 Average | | | | % change from ED1 Average | | | |
|---|---|---|---|---|---|---|---|---|
| | CI (incl. exceptional) | CML | CI (excl. exceptional) | CML | CI (incl. exceptional) | CML | CI (excl. exceptional) | CML |
| LPN | 15 | 16 | 15 | 16 | -2% | -2% | -2% | -2% |
| SPN | 48 | 37 | 44 | 33 | -2% | -2% | -2% | -2% |
| EPN | 48 | 39 | 43 | 33 | -3% | -3% | -3% | -3% |

## 7.5 Consumer Value Propositions

UKPN propose that, rather than funding CVPs up front in totex allowances, the CVP mechanism should be structured along similar lines to the Interruptions Incentive Scheme, sharing the costs and benefits equally between the network companies and customers. Whilst we recognise the incentive properties of this approach, we are concerned that the estimated benefits may be disproportionately shared in favour of the DNOs over their customers.

*CVP1: Fuel poverty support – not recommended*

UKPN propose to directly provide 100,000 customers with practical and financial support. This would be at an estimated cost of £9m and present a net benefit of £5.1m.

Although carved out as a CVP, this is part of UKPN's wider fuel poverty programme. The fact that this type of activity is well established among DNOs raises the question of whether it qualifies for a CVP reward. UKPN's pitch appears to be that it is the scale of the overall programme that is novel.

UKPN propose that c.£9m of customer money would be used to support 100k customers in fuel poverty with support designed to help them realise financial savings. They say that they have used partners' actual delivery data from ED1 and reweighted it to work out a potential saving of up to £375. They have assumed that 64% of people will act and that only 36% of the benefits can be attributed to UKPN's support. They then attribute only half of the remaining benefit to UKPN, acknowledging the role played by the partner agency.

Some of these assumptions look reasonable, but we note that the 64% is based on Energy Saving Trust research into how many people took action after receiving advice on energy efficiency measures. It is not clear whether this was a population of 'vulnerable customers' and, indeed, energy efficiency is only one type of action that UKPN assume people will take; they attribute 65% of the potential savings to other actions (including switching tariffs, changing behaviour and applying for benefits). As a result, we think this take-up assumption should be further discounted. We do, though, note that UKPN make a strong commitment to 'measure, quantify, externally verify and report on' the value actually delivered on an annual basis in combination with a clawback of half the costs, and any benefits not delivered. We were, however, concerned that the costs of delivery appear high compared with other DNOs' costs for similar fuel poverty measures. Overall, we had too many areas of concern to support this as a CVP.

*CVP2: Public charging – not recommended*

UKPN have proposed helping to unlock the public charging market to provide an additional 2400 (20%) of on-street chargers in its areas at a cost of £7.3m (not included in baseline) giving an estimated net benefit of £9.3m. We note that UKPN do not intend to own or operate the charge points.

The Challenge Group recognises the importance of ensuring that there is an adequate charging network for everyone to facilitate the transition to electric vehicles. However, as described, the activities that UKPN will undertake as part of this proposal do not appear to go beyond what could be considered as business as usual for a DNO/DSO in providing network connections and flexibility needed to accommodate the expected rapid growth of distributed energy resources during ED2. Funding through a CVP is not considered appropriate.

*CVP3: Off-gas grid customers – not recommended*

UKPN intend to take a proactive approach to decarbonising heat such that, by the end of ED2, there is suitable network capacity to support the electrification of heat in 242,000 homes in off-gas grid communities. This capacity would be provided at a cost £75m (not included in baseline) and UKPN has estimated the net benefit to be £89m. Under their proposed CVP scheme, UKPN's net share of the benefit would be around £44m.

Whilst we welcome this proactive and collaborative approach, the Challenge Group does not believe that a CVP is the most appropriate funding mechanism for the provision of this additional network capacity or 'anticipatory investment' ahead of need. Also, the approach does not seem to consider alternative non-network energy solutions and could potentially present a barrier to these solutions or lead to nugatory investment. This would appear to be a situation where such investment could trigger an appropriate funding mechanism under the standard price control arrangements once a customer investment signal is obtained.

## 7.6 Finance

UKPN's draft plan was of good quality and we raised relatively few points on it. We did, however, suggest that the company should make very clear what overall cost of equity allowance it had used for its analysis. For reasons which we find difficult to understand (because the BP is, like the draft plan, clearly financeable), a degree of ambiguity remains.

Section 3.4 of the Financial Information Appendix (25a) contains the statement that 'Management remain of the opinion that the financeability assessment should be undertaken based on the allowed cost of capital, not Ofgem's expected cost of capital.' Aside from the fact that this is an expression of opinion as to what should be done rather than a statement of what has been done, this would imply modelling with a cost of equity of 4.4% (the allowed cost of equity) rather than the rate which incorporates Ofgem's 'expected' outperformance i.e. 4.65%. However, the BP is said to be financeable on the basis of Ofgem's W/As which of course include 25 basis points of outperformance. We are therefore assuming that the effective rate for the cost of equity which underlies all of UKPN's analysis is 4.65% but, having pointed out the ambiguity in the draft plan, we think it unfortunate that UKPN have not taken steps to ensure absolute clarity on this crucially important point in their BP. We note that UKPN have moderated (slightly) their proposal in relation to the need for a higher cost of equity allowance but have not made any other amendments to reflect our commentary.

UKPN target a Baa1/BBB+ rating in the base case for both the Notional and Actual Companies. Ofgem is clear that it considers it is for individual DNOs to determine their target ratings. We accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status but we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. We regard Baa1/BBB+ as at the upper end of the acceptable target range and certainly do not consider that a company needs to demonstrate an expectation of that rating in order to be deemed 'financeable'.

UKPN reject some of Ofgem's W/As, describing them (unnecessarily provocatively in our view) as 'errors'. However, subject to the comment above on the assumption used in relation to the cost of equity allowance, they have carried out the full analysis required, for both the Actual and the Notional Companies, on the basis of Ofgem's W/As. The results are well presented with appropriate commentary. They clearly support the target Baa1/BBB+ rating in relation to all three licensees and the Board's statement that the BP is financeable on the basis of Ofgem's W/As. The results, including the downside stress testing are, in our view and subject to our comments about the cost of equity allowance used in the analysis, a very clear demonstration of financeability at an equivalent cost of equity of 4.65%. Results are not shown at 4.4%, but UKPN's position is such that financeability could well be achievable at that level: we regard financeability at least cost to the consumer as very important and consider that it would have been helpful for UKPN to show whether a 4.65% return on equity is really required to finance their Business Plan.

Against this background, we do not consider UKPN's statement that the cost of equity allowance should 'as a minimum be 5.5%' is helpful, in the interests of consumers or, as the company clearly imply, at all necessary for financeability.

We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions. UKPN put forward a number of arguments in support of their proposal for a higher allowance which we do not find persuasive and which we address above.

UKPN's analysis has been based on 60% gearing, its 'natural' capitalisation rate and depreciation over 45 years. Despite Ofgem's requirement to consider alternatives which might support financeability, UKPN reiterate the view, expressed in the draft plan, that they do not regard changes to the depreciation period and the capitalisation rate as 'valid financeability levers'.

UKPN have modelled, as required, on the basis of Ofgem's cost of debt W/A. As noted in our commentary on the draft plan, it is for individual DNOs to determine their debt funding strategies and the extent to which they implement those strategies on a group-wide basis, but we can see no reason for a 'infrequent user' premium in relation to UKPN. The company make a number of comments about the market for CPIH index-linked debt which have been raised by several DNOs and which are therefore dealt with elsewhere in relation to the suite of submissions as a whole.

UKPN's Board Assurance Statement includes a helpfully unambiguous statement that the board has satisfied itself that the BP is 'financeable on both a notional and actual capital structure basis, using Ofgem working assumptions for cost of capital allowances'. As indicated above, we consider this statement to be well supported by the results of the analysis presented in the plan and a clear indication that the company's proposal for an increase in the cost of equity allowance is unnecessary.

# 7. Company report – WPD

As a summary, we have assigned WPD's Business Plan the following ratings:

*Table 102: WPD BP scores*[22]

| | |
|---|---|
| Track record from RIIO-ED1 | 3 |
| Scenarios and forecasts | 4 |
| Totex: LRE, incl. anticipatory investment | 4 |
| Totex: NLRE, incl. asset health | 3 |
| Totex: Network operating costs | 5 |
| Totex: Non-operational costs | 2 |
| Totex: Ongoing efficiency and RPE | 2 |
| Totex: Uncertainty mechanisms | 4 |
| Outputs: DSO and digitalisation strategy | 2 |
| Outputs: Whole system strategy | 2 |
| Outputs: EAP | 3 |
| Outputs: Vulnerability strategy | 4 |
| Outputs: Reliability | 3 |
| Finance | 2 |

| | |
|---|---|
| 5 | High ambition, well justified |
| 4 | Some gaps in ambition and justification |
| 3 | Average ambition and justification |
| 2 | Limited ambition and justification |
| 1 | Low ambition, poorly justified |

In our overall assessment of WPD's BP, we have noted the following key areas of concern, which are further discussed in the following sections:

- **Net Zero –** The baseline scenario appears to be broadly consistent with national Net Zero targets. Load-related capex is forecast to increase by 113% from ED1 levels and we are concerned that this may not fully include benefits from network capacity optimisation.
- **DSO and whole system –** WPD are targeting annual flexibility actions of 610MW, delivering benefits of £94m over ED2. We are concerned that these benefits may not be realised and that potential further benefits may not be reflected in load-related capex forecasts.
- **Costs –** Baseline totex is similar to the draft plan (Best View scenario) but is still forecast to increase by 26% from ED1 before bespoke uncertainty mechanisms are applied. We are concerned that cost increases on a similar underlying asset base are unjustified.
- **Risks and uncertainty –** WPD have proposed load-related uncertainty mechanisms which could add up to £1,295m or 20% of totex. We are concerned that this is a wider than necessary range and that some of these costs may duplicate those already included in baseline expenditure.
- **Finance –** We would like to understand why WPD's Board insist that the plan is not financeable on the basis of Ofgem's Working Assumptions (W/As), given that:
  - WPD's modelling shows that they can achieve Baa2/Baa1 for all four licensees with very little recourse to Ofgem's 'levers' for improving financeability which, if used, seem to us would readily improve the rating by at least a notch; and that,

[22] RAG ratings as shown in the key above only apply to the elements of the BPs assessed as listed here; elsewhere colour-coding is used to signify highs and lows where appropriate, but does not include any element of evaluation as above.

- The plan provides for over £1bn of dividends over the 5 years of the price control.

## 8.1 Track record from RIIO-ED1

We have scrutinised company plan submissions, background materials, and their ongoing performance reports to understand and compare their past performance and their starting point for ED2. To assess this, we have examined the rewards that the DNOs have earned from output and efficiency incentives.

Key performance measures are shown in the tables below. Total ED1 output incentives for Interruptions, Customer Service and Time to Connect is taken from 2021 RRPs and Totex performance from 2021 price control financial models (PCFMs). All data is presented for the 8-year ED1 period with 6 years of actual data and 2 years of forecasts.

*Table 103: WPD ED1 performance summary*

| **ED1 performance (2021 RRP)** | **WPD** |
|---|---|
| *Output incentives* | |
| Interruptions (IIS) | 1.5% |
| Customer service (BMCS) | 0.6% |
| Time to connect (TTC) | 0.2% |
| **Output incentives total** | 2.3% |
| | |
| **Totex efficiency incentives** | 0.1% |
| **Operational RoRE** | 9.5% |

**ED1 - Totex (2021 PCFM)**

| **£m (2012/13 prices)** | **WPD** |
|---|---|
| Totex allowance | 6984 |
| Totex actual/forecast | 6890 |
| % totex (under)/overspend | (1%) |
| % LRE (under)/over spend | (7%) |
| % Totex (excl. LRE) (under)/overspend | (1%) |

Overall, we note that WPD's plan forecasts an ED1 outturn of a 0.3% underspend of their allowance instead of the 1% shown in the PCFM, with an underspend on LRE of 10% (before indirect allocations) by the end of ED1.

Asset health targets are expected to be delivered by the end of ED1.

Interruptions incentive (IIS) reward is amongst the highest of all DNOs and the customer service incentive (BMCS) is also amongst the highest.

## 8.2 Costs, scenarios and forecasts

### 8.2 (i) Scenarios and forecasts

We welcome the wide range of scenarios from WPD and that these scenarios appear to be consistent with Net-Zero targets. We note that the company have used a Best View scenario which they have identified as the highest certainty scenario that does not foreclose network future-proofing and informs the RIIO-ED2 baseline (ex-ante) allowance.

By the end of ED2, WPD forecast they will have connected:

- 2,079k EVs and 893k heat pumps under their Best View scenario; and,
- 2,744k EVs and 1,522k heat pumps under their Upper View.

These scenarios are presented below as 'Best View' and 'Upper View'.

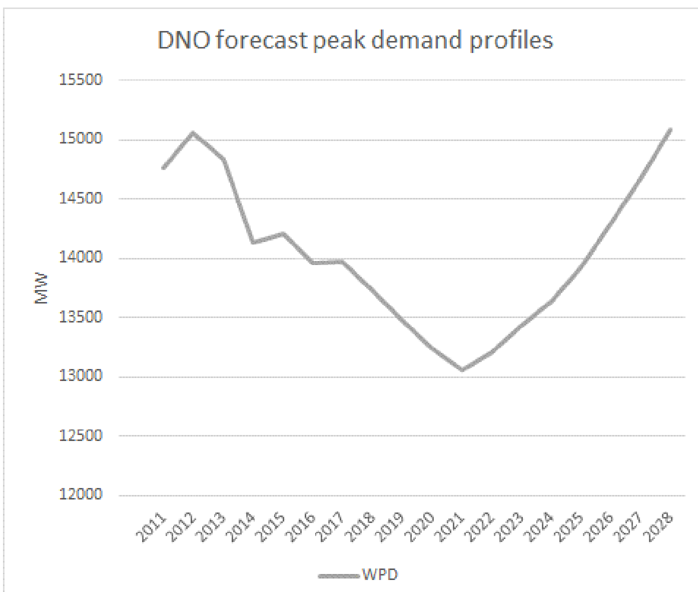
*Table 104: WPD low-carbon technology scenarios*

| | Best view | | | | Upper view | | | |
|---|---|---|---|---|---|---|---|---|
| | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs | 2028 EVs ('000) | % of customers with EVs | 2028 HPs ('000) | % of customers with HPs |
| WPD | 2079 | 25% | 893 | 11% | 2744 | 34% | 1522 | 19% |

WPD have around 26% of the networks' total customer base. The forecast number of EVs in the Best View scenario across this customer base in 2028 is broadly in line with the ESO 2021 FES Consumer Transformation or Leading The Way scenarios, which forecast around 8.4m BEVs (cars and vans) and are at the higher end of the forecast uptake of low-carbon technologies by consumers.

The WPD submission of demand profiles in the BPDTs (shown below) shows an increase of around 14% between 2020 and 2028, which is higher than the equivalent peak demand increase of 11% forecast in the ESO 2021 'Consumer Transformation' scenario.

*Chart 37: WPD forecast peak demand profile*




Overall, we consider that WPD have undertaken effective scenario planning, taking account of upward and downward demand drivers, and provided scenario assumptions that are consistent with relevant national forecasts.

### 8.2 (ii) Totex forecasts

We have evaluated company totex forecasts by comparing them against each company's prior track record during ED1 and then between companies. We have looked for evidence to:

- Justify costs and volumes, including cost drivers, and volume options considered.
- Describe how efficiency and innovation will be used to reduce costs, including savings from DSO and flexibility capabilities.

All numbers provided in this report have been sourced by the Challenge Group from the individual company data table submissions to ensure consistency and are stated in 2020/21 prices. While we have sought in the time available to ensure data is accurately presented, we are aware there may be some minor differences with our costs and those in company plans due to alternative cost allocations and reconciliations. We expect these differences to be addressed by Ofgem and companies prior to Draft Determinations. Comparisons between the 8-year ED1 price control and the 5-year ED2 price control have compared equivalent annual averages.

The WPD ED2 bid for baseline totex (before adjustments for ongoing efficiency and real price effects) totals £6,535m and is a 24% increase on the annual average expenditure rate during ED1. We note that this forecast is not directly comparable with their draft plan submission where data was submitted on a different scenario (WPD's 'Certain View' which included some LRE in uncertainty mechanisms) but also note that, once this change is taken into account, the overall totex bid remains very similar.

The following table compares the WPD cost submissions between ED1 actuals/forecasts and ED2 forecasts. It also compares the draft and final plans.[23]

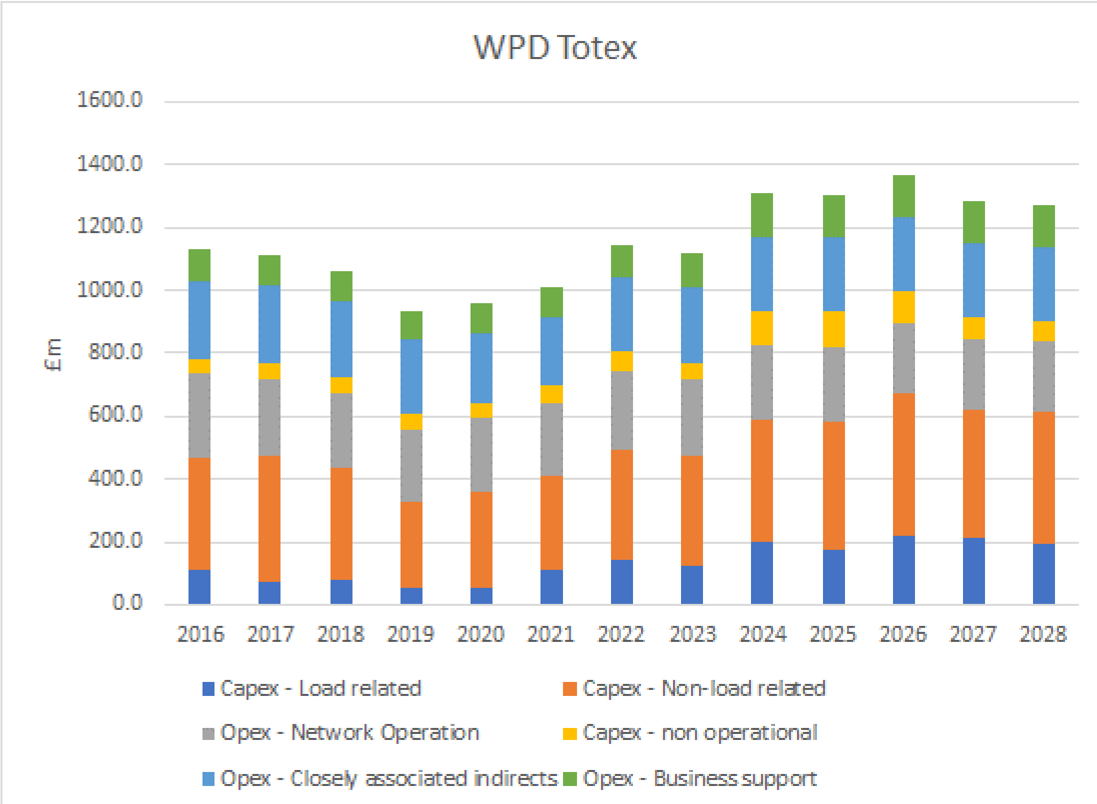
*Table 105: WPD overall totex comparison*

| WPD | Final plan | | | | | Draft plan | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Totals | | Averages | | % change | Totals | | Averages | | % change |
| Overall | ED1 | ED2 | ED1 | ED2 | ED1-ED2 | ED1 | ED2 | ED1 | ED2 | ED1-ED2 |
| Capex - Load related | 757.9 | 1007.2 | 94.7 | 201.4 | 113% | 760.9 | 623.9 | 95.1 | 124.8 | 31% |
| Capex - Non-load related | 2683.7 | 2077.0 | 335.5 | 415.4 | 24% | 2653.6 | 2013.0 | 331.7 | 402.6 | 21% |
| Opex - Network Operation | 1929.7 | 1134.2 | 241.2 | 226.8 | -6% | 1922.7 | 1117.2 | 240.3 | 223.4 | -7% |
| Capex - non operational | 410.1 | 456.1 | 51.3 | 91.2 | 78% | 409.2 | 447.9 | 51.2 | 89.6 | 75% |
| Opex - Closely associated indirects | 1894.1 | 1172.1 | 236.8 | 234.4 | -1% | 1896.3 | 1130.2 | 237.0 | 226.0 | -5% |
| Opex - Business support | 789.5 | 688.6 | 98.7 | 137.7 | 40% | 783.8 | 633.1 | 98.0 | 126.6 | 29% |
| **Totex** | 8465.0 | 6535.2 | 1058.1 | 1307.0 | 24% | 8426.7 | 5965.3 | 1053.3 | 1193.1 | 13% |
| **Baseline totex after OE/RPE adjustments** | | | 1058.1 | 1341.1 | 27% | | | | | |
| **Baseline totex with UMs (excl. Access SCR)** | | | 1058.1 | 1600.8 | 51% | | | | | |

A profile of the totex and main expenditure categories is shown below. It shows a gradual increase at the start of ED2.

[23] Note: These totex figures exclude 'other costs outside the price control'. The adjustments remove forecasts for operating efficiency and add forecasts for real price effects to put totex on a comparable basis. Uncertainty mechanism adjustments reflect the bespoke uncertainty forecasts made by companies but exclude impacts from potential access reforms.

*Chart 38: WPD overall totex profile*




We consider that the 8-year ED1 totex track record gives a reasonable guide to the efficient level required for a large amount of underlying ongoing expenditure, and we have scrutinised reasons for increases from these levels. Our assessments for these individual cost categories are set out below, seeking to understand the justifications for these potential increases.

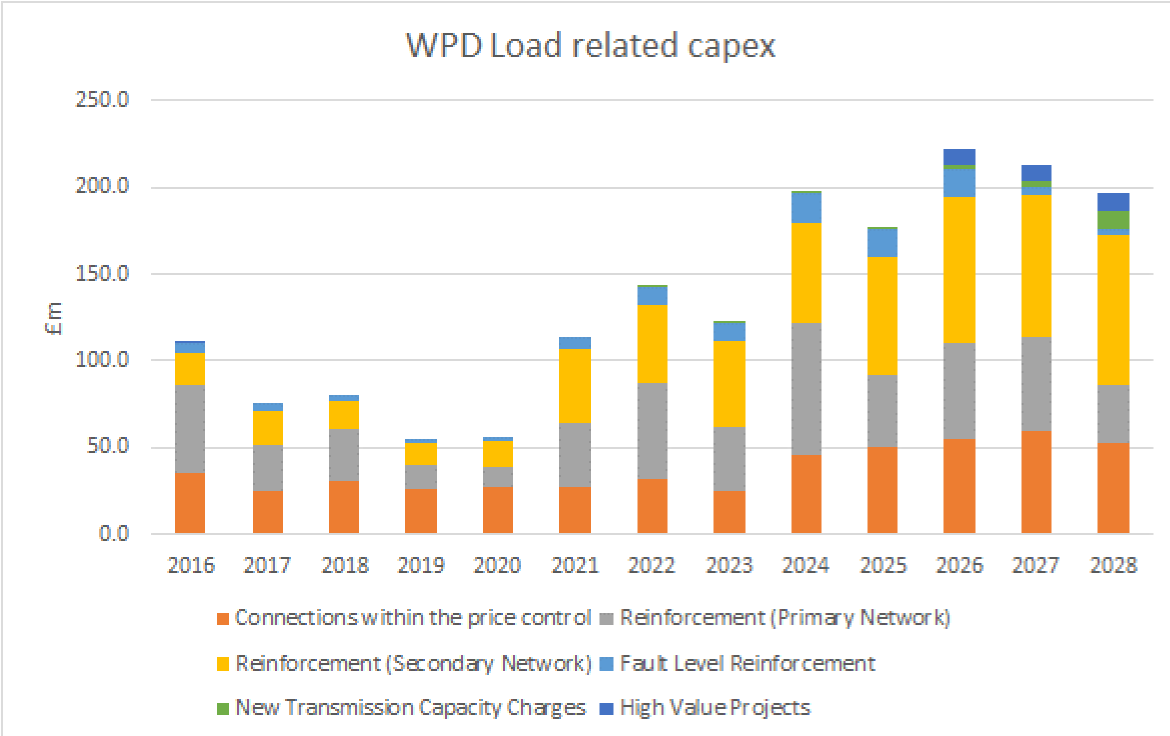
### *ii.a. Totex: LRE*

*Table 106: WPD load-related capex comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Capex - Load related** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Connections within the price control | 228.9 | 265.2 | 28.6 | 53.0 | 85% |
| Reinforcement (Primary Network) | 261.6 | 261.2 | 32.7 | 52.2 | 60% |
| Reinforcement (Secondary Network) | 219.5 | 373.9 | 27.4 | 74.8 | 172% |
| Fault Level Reinforcement | 46.4 | 59.1 | 5.8 | 11.8 | 104% |
| New Transmission Capacity Charges | 1.3 | 17.5 | 0.2 | 3.5 | >1000% |
| High Value Projects | 0.2 | 30.3 | 0.0 | 6.1 | >1000% |
| **Total load related costs** | 757.9 | 1007.2 | 94.7 | 201.4 | 113% |

A profile of the LRE expenditure categories is shown below, showing a significant increase over the course of ED2.

*Chart 39: WPD load-related capex profile*




We consider that WPD have provided reasonable justifications for increases in LRE, especially relating to the need to address anticipated LV network capacity constraints to connect low-carbon technologies. However, while WPD has identified savings of £181m from flexibility, smart meter data and LV monitoring, we were concerned that WPD's plan had not fully considered the availability of current capacity headroom, and the benefits from flexibility and smart control to enhance network utilisation. As such, the proposed baseline bid appears uncertain and may be overstated – a further proportion of this may be best addressed through uncertainty mechanisms.

While we note that WPD has proposed symmetrical uncertainty mechanisms, we are concerned that they may be unduly generous to companies. We suggest that LRE links with uncertainty mechanisms should be appropriately calibrated and that price control deliverables are used to ensure that this important Net Zero enabling investment is actually delivered.

***ii.b. Totex: NLRE***

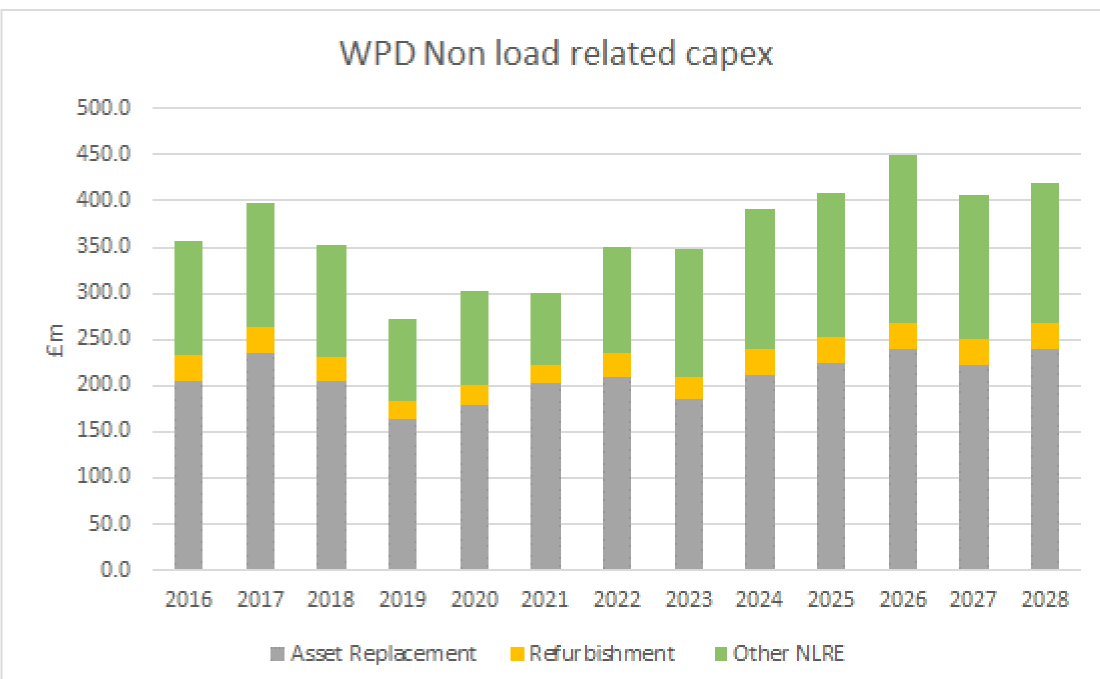
The WPD bid for baseline NLRE is £2,103m, which represents a 26% increase from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories, with reinforcement relating to asset replacement, and operational IT and telecoms showing significant increases in particular.

*Table 107: WPD non-load-related capex comparison*

| Capex - Non Load related | Totals ED1 | Totals ED2 | Averages ED1 | Averages ED2 | % change ED1-ED2 |
|---|---|---|---|---|---|
| Diversions (Excluding Rail Electrification) | 310.5 | 244.2 | 38.8 | 48.8 | 26% |
| Diversions Rail Elec | 13.8 | 0.0 | 1.7 | 0.0 | -100% |
| Asset Replacement | 1586.2 | 1139.2 | 198.3 | 227.8 | 15% |
| Refurbishment | 189.2 | 139.5 | 23.6 | 27.9 | 18% |
| Civil Works Condition Driven | 119.1 | 68.6 | 14.9 | 13.7 | -8% |
| Operational IT and telecoms | 127.4 | 234.9 | 15.9 | 47.0 | 195% |
| Blackstart | 23.3 | 0.0 | 2.9 | 0.0 | -100% |
| BT21CN | 11.1 | 0.0 | 1.4 | 0.0 | -100% |
| Legal & Safety | 42.6 | 44.9 | 5.3 | 9.0 | 69% |
| QoS & North of Scotland Resilience | 51.7 | 25.3 | 6.5 | 5.1 | -22% |
| Flood Mitigation | 9.1 | 11.7 | 1.1 | 2.3 | 106% |
| Physical Security | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| Rising and Lateral Mains | 0.0 | 2.1 | 0.0 | 0.4 | n/a |
| Overhead Line Clearances | 147.1 | 122.3 | 18.4 | 24.5 | 33% |
| Worst Served Customers | 4.4 | 4.4 | 0.6 | 0.9 | 60% |
| Environmental Reporting & Losses | 48.2 | 40.1 | 6.0 | 8.0 | 33% |
| HVP | 0.0 | 0.0 | 0.0 | 0.0 | n/a |
| **Total non load related capex** | 2683.7 | 2077.0 | 335.5 | 415.4 | 24% |

A profile of the NLRE expenditure categories from 2016 to 2028 is shown below, showing a gradual increase over ED2.

*Chart 40: WPD overall non-load capex profile*



We recognise that there are some upward cost drivers in relation to DSO and network visibility investment, and from accelerated PCB removal. However, we do not think the scale of NLRE expenditure increases for ED2 have been justified given much of the underlying asset base remains largely the same as for ED1.

We have looked specifically at the NARMs asset health proposals which cover around 60% of all non-load assets and shows the forecast asset risk targets and associated mitigation costs. We note that WPD are targeting a network risk target of 32%, resulting in a closing ED2 position of 2.8% above opening. The forecast monetised risk reduction is 44.2 pence per point. We note that WPD are forecasting at the end of ED2 a network risk target of 32% without intervention and a target after intervention of 2.8%.

We welcome that WPD are targeting a total network risk target of 2.8% for the end of ED2. For our assessment of whether asset replacement expenditure has been justified, we have selected an example to consider in more detail. We have compared DNO plans for low voltage (LV) wood pole replacement. These assets comprise a significant element of the asset base for most DNOs and their forecasts are based on their assumptions about risk associated with these assets. The WPD profile is shown below:

*Table 108: Low voltage pole annual average replacement numbers*

| | DPCR5 Av. Annual | ED1 Av. Annual | ED2 Av. Annual | DPCR5 to ED1 % Change | ED1 to ED2 % Change |
|---|---|---|---|---|---|
| WMID | 1288 | 1852 | 1843 | 44% | -1% |
| EMID | 919 | 1025 | 1100 | 12% | 7% |
| SWEST | 2628 | 3483 | 3674 | 33% | 6% |
| SWALES | 1733 | 1206 | 1313 | -30% | 9% |
| TOTAL | 6568 | 7566 | 7930 | 15% | 5% |

The average annual number of LV poles to be replaced during ED2 has increased by 5%. The increasing number of LV poles in high-risk categories appears to be driven primarily by age, supplemented with asset condition information provided by foot patrols. Whilst the small increase in number of poles to be replaced would appear to be within reasonable expectations, we would have liked the EJP to have considered a more robust analysis of the options.

### *ii.c. Totex: Network operating costs*

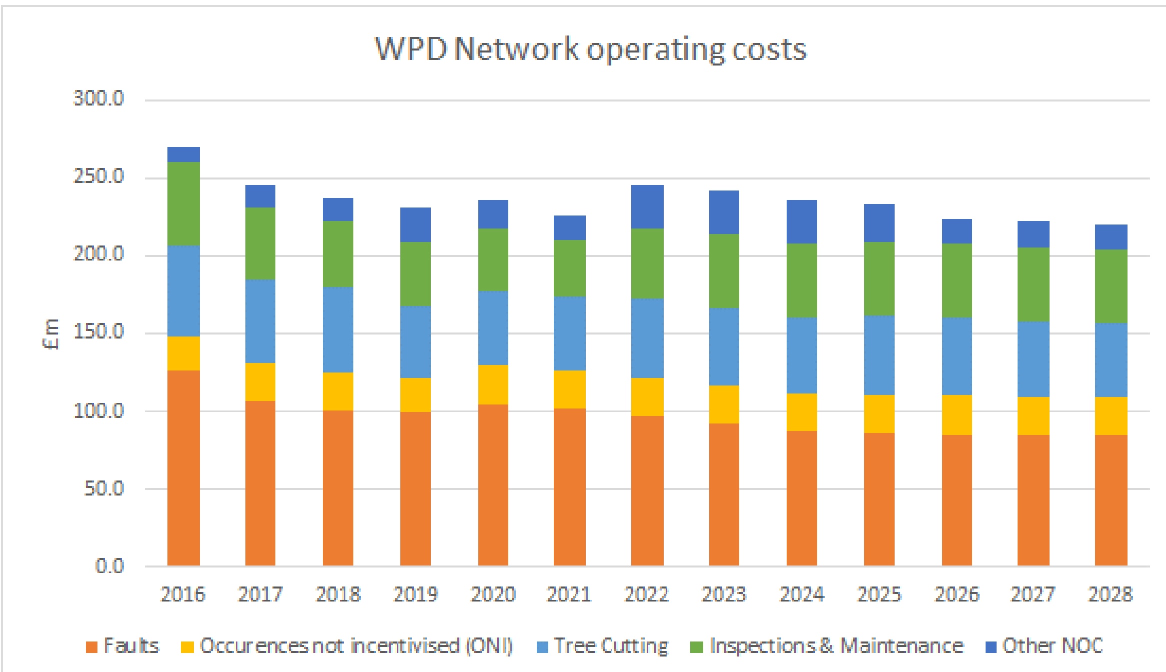
The WPD bid for network operating costs is £1,134m, which represents a 6% decrease from their ED1 averages. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 109: WPD network operating cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Opex - Network Operating Costs** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Faults | 827.7 | 427.9 | 103.5 | 85.6 | -17% |
| Severe Weather 1 in 20 | 13.5 | 31.4 | 1.7 | 6.3 | 271% |
| ONIs | 191.1 | 122.6 | 23.9 | 24.5 | 3% |
| Tree Cutting | 408.6 | 246.3 | 51.1 | 49.3 | -4% |
| I&M | 353.4 | 236.3 | 44.2 | 47.3 | 7% |
| NOCs Other | 75.5 | 53.0 | 9.4 | 10.6 | 12% |
| Smart Meters | 59.8 | 16.7 | 7.5 | 3.3 | -55% |
| **Total Network Operating Costs** | 1929.7 | 1134.2 | 241.2 | 226.8 | -6% |

A profile of the network operating cost expenditure categories from 2016 to 2028 is shown below. The profile increases over the first two years of the ED2 period.

*Chart 41: WPD overall network operating cost profile*




Overall, we consider that WPD have provided reasonable justifications in respect of these costs. We welcome the fact that WPD have been able to propose a decrease in these costs while still proposing improvements to reliability targets.

### *ii.d. Totex: Non-operational costs*

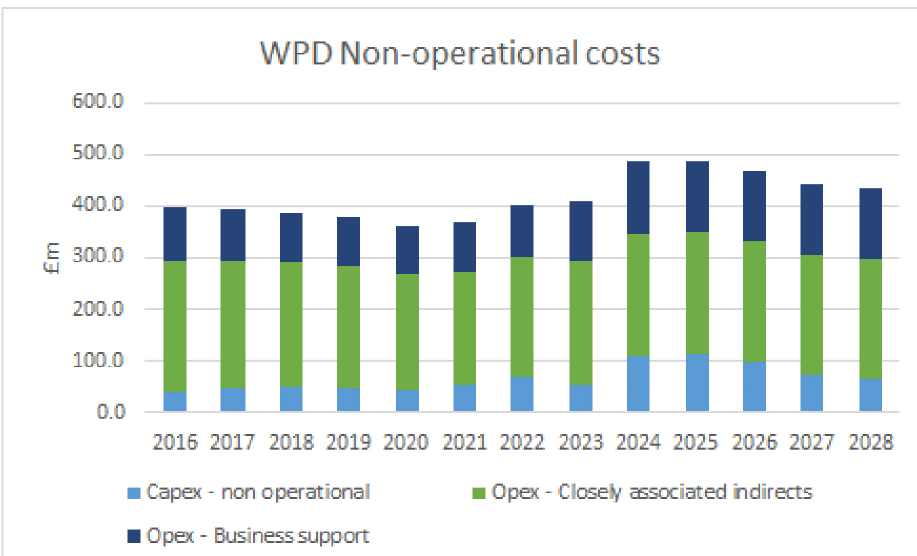
Under this cost grouping we have included business support, closely associated indirects (CAI) and non-operational capex. The WPD bid is for £689m of business support costs (an increase of 40%), £1,172m of closely associated indirects (a decrease of 1%), and £456m of non-operational capex (an increase of 78%). The combined increase is 20%. The following table shows the breakdown of these costs by the individual business plan categories.

*Table 110: WPD non-operational cost comparison*

| | Totals | | Averages | | % change |
|---|---|---|---|---|---|
| **Business Support** | **ED1** | **ED2** | **ED1** | **ED2** | **ED1-ED2** |
| Core BS | 338.6 | 262.9 | 42.3 | 52.6 | 24% |
| IT& Telecoms (Business Support) | 305.2 | 338.3 | 38.1 | 67.7 | 77% |
| Property Mgt | 145.6 | 87.4 | 18.2 | 17.5 | -4% |
| **Total Business Support Costs** | 789.5 | 688.6 | 98.7 | 137.7 | 40% |
| **Closely associated indirects** | | | | | |
| Core CAI | 1286.5 | 816.4 | 160.8 | 163.3 | 2% |
| Wayleaves | 219.3 | 137.5 | 27.4 | 27.5 | 0% |
| Operational Training (CAI) | 237.2 | 132.9 | 29.7 | 26.6 | -10% |
| Vehicles and Transport (CAI) | 151.2 | 85.3 | 18.9 | 17.1 | -10% |
| **Total CAI** | 1894.1 | 1172.1 | 236.8 | 234.4 | -1% |
| **Non-operational capex** | | | | | |
| IT and Telecoms (Non-Op) | 155.2 | 241.0 | 19.4 | 48.2 | 149% |
| Property (Non-Op) | 79.1 | 57.0 | 9.9 | 11.4 | 15% |
| Vehicles and Transport (Non-Op) | 97.9 | 111.9 | 12.2 | 22.4 | 83% |
| Small Tools and Equipment | 78.0 | 46.3 | 9.8 | 9.3 | -5% |
| **Total non-op capex** | 410.1 | 456.1 | 51.3 | 91.2 | 78% |

We welcome that CAI costs show a decrease despite the major increase in load related expenditure over the ED2 period. A profile of the non-operational cost expenditure categories from 2016 to 2028 is shown below. The profile shows a sharp increase at the start of the ED2 period and continues thereafter.

*Chart 42: WPD overall non-operational cost profile*




While we welcome that closely associated indirect (CAI) costs are expected to reduce slightly, there are significant increases in business support and non-operational capex that we think are not justified. For example, an 83% increase in vehicle costs appears exceptionally high. While we note that WPD has provided evidence to support cost increases, we are concerned that efficiency opportunities have not been sought with corresponding rigour, and these non-operational costs may be overstated as a result.

#### *ii.e. Totex: Ongoing efficiency and RPE*

We are looking for companies to demonstrate ambition in their ongoing efficiency challenge, but also not to offset this through unjustifiably high real price effect adjustments. WPD have proposed an ongoing annual efficiency challenge of 0.5%. As shown below, the corresponding forecasts in business plan data tables indicate an overall ED2 saving of 1.5%. WPD are forecasting real price effects over ED2 that total 4.8%.

*Table 111: WPD Ongoing efficiency and RPE forecasts*

| | Real Price effects | | Ongoing efficiency | | |
|---|---|---|---|---|---|
| | £m RPE | % of totex | £m OE | % of totex | ED2 Totex (£m) |
| WPD | 310 | 4.8% | 96 | 1.5% | 6535 |

WPD's OE forecast is amongst the lowest of the companies. However, we suggest that a more ambitious level of OE would be appropriate given the major cost increases that are being proposed.

### 8.2 (iii) Uncertainty mechanisms

WPD have only proposed a load-related uncertainty mechanism and have included an additional £1,295m or 20% of their proposed baseline totex to be addressed by this mechanism.

We agree that a LRE uncertainty mechanism is necessary, or it could lead to consumers either bearing the cost of additional LRE expenditure which turns out not to be needed or providing a windfall gain from underspend. While we welcome WPD's proposal for a symmetrical uncertainty mechanism, we are concerned with the potentially large proportion of WPD's price control that may be covered by this mechanism and would suggest that this may be too wide a range for an effectively calibrated, value for money automatic mechanism to be confidently established. We suggest that Ofgem carefully considers the proposed design of this mechanism in this context.

## 8.3 DSO and whole system

### 8.3 (i) DSO and digitalisation strategy

WPD's business plan identifies four areas where they will implement change to support their DSO and whole system strategy. These are:

- Rapid connection of low-carbon technologies;
- Expand flexibility services;
- Support community energy developments to gain connections; and,
- Provide automatic access to open data.

WPD are proposing to spend £260m on DSO activities in ED2 (with 72 staff by 2028) and are targeting 11% of secondary substations (from 2% at start of ED2) to have metering installed by end of ED2. WPD have the lowest level of LV monitoring across all DNOs. The plan states that £59m of reinforcement will be deferred through increased LV monitoring. We note that WPD is planning to use smart meter data to target their monitoring at substations that offer the greatest benefit first.

The following table assesses the company proposals for MW of DSO benefits during ED2 and compares these forecasts with their marginal increase in peak demand between 2020 and 2028, and also with their forecast 2028 peak demand.

*Table 112: DSO flexibility and smart grid benefits for ED2*

| | DNO 2028 peak MW | 2020-28 peak MW increase | DNO ED2 flex forecast (MW) | % flex of 2028 peak MW | % flex of 2020-28 MW increase | Direct ED2 DSO and flex savings (£m) |
|---|---|---|---|---|---|---|
| WPD | 15,079 | 1842 | 610 | 4% | 33% | 94 |

WPD are targeting 610MW of flexibility to be procured during ED2, or 4% of peak demand, resulting in £94m of savings. While this is welcome, we are concerned that these benefits may not be delivered, and that further benefits are not pursued, including from interaction with the ESO.

The DSO plan is high level, with a lack of ambition and giving limited confidence that the plan and associated benefits can be delivered. Potential visibility and flexibility benefits are uncertain. Overall, based on our review of supporting materials, we think the DSO plan is weak and means that potential benefits to consumers from these activities will be lost.

***Digitalisation***

WPD's plan for ED2 identifies a digitalisation roadmap. They propose to use digitalisation to focus on improved network data visibility for customers, smart system control, and workforce productivity. Based on our limited review in the time available of the supporting materials provided by WPD, our view is that the WPD digitalisation plan is weak and raises concerns about both delivery and the achievement of benefits, especially related to network flexibility and enhancing network utilisation through smart control.

**8.3 (ii) Whole system strategy**

WPD's whole system strategy seeks to expand their approach to a 'very broad' whole system, where they collaborate beyond the whole system energy vectors of power, transport, and heat to encompass other utilities and societal systems, including water, health and the built environment. WPD's whole system action plan to support this includes the following initiatives:

- Internal whole systems training;
- Establishment of a whole system management team;
- Whole system workshops with stakeholders;
- Collaboration with Welsh Assembly, NG, WWU and SPEN;
- Funding streams for community energy groups;
- Net Zero South Wales initiative;
- Increasing flexibility to address network constraints;
- Further development of Regional Development programmes;
- Peak heat study to develop demand profiles for heat electrification;
- Cost benefit analysis tools; and,
- A whole system coordination register.

While WPD proposes a long list of whole system initiatives, most of these may be considered as an evolution of business-as-usual, and do not demonstrate a step change in approach. We have commented on CVPs separately.

Overall, despite the aim of expanding their whole system approach to be very broad, we are concerned that WPD's approach to whole system initiatives still appears to retain a narrow focus on initiatives impacting its own network. WPD consider an evolutionary approach rather than a step change to be the most appropriate and that this is supported by their stakeholders. But we consider the WPD whole system vision and delivery plan could be more ambitious and more fully consider alternative non-network solutions for example. While outreach to third parties is welcome, there is little to demonstrate how consumers will benefit from these actions.

## 8.4 Other outputs

### 8.4 (i) Environmental Action Plan

WPD have a well-developed, multi-period environment strategy. Their EAP for ED2 also points to a well-established and embedded commitment to decarbonisation and environmental stewardship, but the actions to achieve its longer-term goals do not seem to us to be as clearly thought through as in some plans. There is no attempt to describe best practice or to use benchmarking on the face of the plan. Although WPD make reference to the UN SDGs, they only currently address 3 of them.

In relation to SBT and target for BCF reduction, WPD have committed to a 1.5°C trajectory for scopes 1 and 2. This is essentially now required for an SBT under revised criteria and it is the standard which other DNOs have set. In our view WPD are unambitious on scope 3 emissions – essentially committing to assess and report.

Despite our challenge, they are still proposing to achieve Net Zero by 2028. This will require substantial offsetting, with no apparent explanation as to why this target is considered appropriate given the SBTi's emphasis on the need for clear and consistent use of the concept of Net Zero (with a focus on carbon reduction to achieve short and mid-term targets and a requirement that companies with an SBTi only seek to achieve Net Zero through use of offsetting as a last step when all practicable reductions have been achieved). Whilst the distinction between SBT reductions and Net Zero internal BCF via abatement, insetting and offsetting is acknowledged, there is much less clarity than we would like about how much will be achieved by reduction and how much by offsetting. For example, they refer in the Business Plan to taking actions by the end of RIIO-ED2 to reduce their BCF to achieve Net Zero by 2028 without making clear that the actions will only reduce emissions by 60-70% and that 2028 target assumes substantial offsetting – about ⅓ of reduction required. The discussion of trade-off seems to compare two extremes (2028 or 2043) whereas SBTi guidance clearly suggests focusing on reduction until the lowest possible residual carbon has been achieved.

WPD are proposing reasonably ambitious scale and pace of fleet electrification with no mention of price comparison for biogas or hydrogen. The fleet electrification plan looks to us to be very expensive, compared to other DNOs, even taking account of scale. It appears the volumes are driven by the 2028 Net Zero target and the unit costs seem high and, as with other DNOs, seem to relate to difference in upfront cost rather than difference in incremental whole life cost.

WPD's $SF_6$ strategy effectively sets out the standard approach of repair/replace and introduce substitutes as available. In our opinion there is no impression that WPD are looking to achieve a step change in performance and present ambition in this area looks weak.

Their losses strategy will encompass voltage reduction as well as the measures to mitigate losses adopted through ED1 (eco design standards; larger cables).

WPD have put forward two CVPs related to their EAP, which are further discussed in their CVP section.

### 8.4 (ii) Vulnerability strategy

This is a strong strategy that has been informed by extensive, iterative stakeholder engagement and the insights from that work are clearly set out. It makes sophisticated use of data and draws on the insight and delivery expertise of an extensive range of partners.

WPD have changed the way that they measure the reach of its PSR and are now targeting 75% of all eligible households, up from the current 59%. They have set themself an additional target of signing up 80% of households with 'critical medical dependencies'.

In terms of power cut support, we welcome the fact that they plan to work with stakeholders to develop resilience plans for premises that provide care and support for people who would be particularly vulnerable in the event of a power cut. This includes care homes as well as refuges and shelters. They have set a specific target for the scale of their support for care homes, saying that they will support 10% of those in their region to create a resilience plan. We asked all DNOs to explain how they measured the reach and effectiveness of the support provided during a power cut. WPD responded by saying that one of the ways they did this was to follow up with all customers who contacted WPD by phone or text during a loss of supply to apologise and to ask for feedback on its support. This is positive, although it does not give details of what it has learned from the feedback or how it adds to a more comprehensive understanding of the reach and impact of the support provided.

WPD have a strong track record in the early years of ED1 of delivering support for customers in fuel poverty; the plan says that they have delivered savings of £37m for 92k customers in the first six years of ED1. During ED2, they say they will support 113k fuel poor customers to save £60m – a financial saving which they say is double what they have delivered in ED1 on a like-for-like five-year basis. In ED1, WPD have focused on capturing the hard, financial 'direct savings' delivered to customers. They will build on this in ED2 to use the social value method also adopted by other DNOs. We hope that, in addition to using the common SROI method, WPD will retain their focus on quantifying, and reporting on, the tangible, direct savings and benefits achieved by customers – and that other DNOs will do the same.

The main emphases of WPD's support in the context of the energy transition were the 'bespoke smart energy action plans' put forward as a CVP (discussed in WPD's CVP section). WPD have clarified that these activities are a core commitment of their Business Plan, and that they will be delivered regardless of whether or not they are accepted for a CVP reward.

We identified a range of activities in the strategy that demonstrated and supported organisational commitment to this work. These include commitments: that WPD will work with expert referral partners each year to 'co-create an ambitious annual action plan' and update to its vulnerability strategy; that every WPD innovation scheme will formally consider the impacts and opportunities for customers in vulnerable situations; and, that a senior executive (WPD's Resource and External Affairs Director) will provide strategic direction for the work and ensure it is embedded in company-wide operations.

### 8.4 (iii) Reliability

In ED1, WPD's customers lost fewer minutes to power cuts than customers of many other DNOs, but their performance in terms of the number of power cuts was more mixed. Their proposed targets for ED2 would leave them in a similar position relative to other networks. Their plan flags that, in ED1, they have reduced the number of customers experiencing particularly long power cuts – of more than 12 hours – from almost 10.7k to just 155. They say that, in ED2, they will continue to 'do everything that is safe and practical' to get the power back on for customers in less than 12 hours. They also aim to improve reliability for c.90% of the c.9,200 customers on their worse-served customer list. The plan was unclear about the nature or scale of the improvement (although they said it would be 'significant'), and we were unclear how many customers would be removed entirely from their WSC list by the projects proposed. However, in response to this challenge, WPD told us that, where they carried out an improvement project in ED2, they would expect all the customers affected to be removed from the WSC list.

*Table 113: WPD's reliability 'targets' for Customer Interruptions (CI) and Customer Minutes Lost (CML), and the change they represent compared with WPD's performance in ED1.*

| | ED2 Average | | | |
|---|---|---|---|---|
| | CI (incl. exceptional) | CML (incl. exceptional) | CI (excl. exceptional) | CML (excl. exceptional) |
| EMID | 37 | 19 | 37 | 19 |
| WMID | 49 | 26 | 49 | 25 |
| SWEST | 50 | 32 | 49 | 30 |
| SWALES | 41 | 21 | 38 | 19 |

| | % change from ED1 Average | | | |
|---|---|---|---|---|
| | CI (incl. exceptional) | CML (incl. exceptional) | CI (excl. exceptional) | CML (excl. exceptional) |
| EMID | -12% | -14% | -11% | -13% |
| WMID | -11% | -12% | -7% | -7% |
| SWEST | -8% | -10% | -4% | -8% |
| SWALES | -9% | -6% | -8% | -5% |

## 8.5 Consumer Value Propositions

*CVP1: Net Zero by 2028 – not recommended*

WPD are committed to becoming a Net Zero carbon organisation in 2028 and to adopting a "stretching" Science Based Target of 1.5°C trajectory. The key element of this CVP is the proposal for an early Net Zero date but the adoption of the 1.5°C target is also referred to in the headline description. The gross cost in baseline in relation to this CVP, £89.1m, includes cost of fleet replacement with EVs, installation of electric vehicle charging, installation of solar panels at offices and depots. In addition, there is an estimated £1m over ED2 to achieve offsetting via tree planting. Net benefits of £14m are based on a combination of Willingness to Pay and cost savings.

The Challenge Group acknowledges that achieving a substantial reduction in WPD's BCF is an important priority for ED2, and stakeholder evidence indicates that it is something which customers support. However, we do not think that this proposal should qualify for a CVP reward. The various measures outlined do not go beyond the efficient and economic actions to reduce controllable BCF that are part of Ofgem's expectation for the EAP. Moreover, actions of this kind will be required to meet the SBT, which is also an Ofgem requirement. We have a specific concern about the use of offsetting to achieve an early Net Zero, given that the SBTi is specifically seeking to establish a framework and standard for setting science-based Net Zero targets with a focus on rapid, deep, emission cuts, near- and long-term science-based targets and, crucially, no Net Zero claims until long-term targets are met.

*CVP2: Proactively partner with every LA to develop LAEPs – not recommended*

WPD aim to help LAs and developers to create local energy plans that are high ambitious and achievable, to deliver a network ready for the future, as quickly as possible. These plans will feed into WPD's long-term strategic planning. WPD intend to ensure these plans are of high quality, conducted by WPD staff with adequate skills and knowledge, and they will seek feedback to identify improvements. Costs of £2m and net benefits of £28m are stated in the plan.

The Challenge Group acknowledges that Local Authorities are likely to see value in the provision of this service. But we are also concerned that, as structured, the resources provided to LAs may be overly aligned with the network interests of DNOs, rather than considering non-network solutions. We are not convinced that WPD have the capability to deliver such whole energy system plans.

Furthermore, we consider that such proactive Local Authority engagement should be a business-as-usual activity as other DNOs are planning. For example, the following diagram is taken from UKPN's Local Area Energy Planning Framework appendix to their business plan, which is included in their baseline plan. We consider that this represents an appropriate balance for DNO engagement to deliver whole system solutions with Local Authorities and other local groups. The proposed 'Middle Ground' option described below would appear to still offer a proactive approach without the risk of DNO network solutions dominating.

| | DNO Light Touch | Middle Ground | DNO Driven |
|---|---|---|---|
| Mode of engagement | *Purely reactive responding to connection request* ***May drive unnecessary delays*** | *Collaborative engagement with pre-agreed criteria & format* | *Network pro-actively drives local planning* ***Risks not being aligned to the needs of local stakeholders & customers*** |
| Level of detail | *Conduct only high level assessments of plans* ***May result in regret spend*** | *Ensure minimum confidence is met across key criteria & account for differing confidence levels* | *Require full cross vector energy system modelling & least worst regrets assessment* ***Would require additional resource & time*** |
| | | What we are aiming for | |

*CVP3: Establish Community Engineers – suggest inclusion in baseline*

Supporting community energy projects has been identified by WPD as an important area of focus (reflecting the nature of the area it serves) and has strong stakeholder support. This CVP builds on WPD's accessible guides and responds to stakeholder engagement in proposing to employ four full-time Community Energy Engineers, each dedicated to a licensed area, and significantly expand their provision of Community Energy Surgeries. It also supports their commitment to connect at least 30 community energy projects each year. The cost of this proposal is £1.3m (included in baseline) and WPD estimates that it will deliver £3.1m of financial and societal net benefits during ED2.

The Challenge Group acknowledges the strong stakeholder support for this CVP and agrees that Community Energy Engineers could be helpful in supporting the development of local energy projects. However, we are not convinced that this proposal goes beyond business as usual connections engagement with customers, or that WPD have the capability to provide resources that will need to be versed in non-network energy solutions.

Overall, we see potential in this proposal but are concerned that the relatively low specified benefits will be difficult to measure and reward under a CVP. We think the costs need to be scrutinised and we would also want reassurance that the engineers would be able to be sufficiently independent in putting forward solutions (rather than advancing proposals which are in the network's best interests). Such activities may be better served as being including in baseline expenditure alongside a commitment to deliver.

*CVP4: Funding solar PV on schools – not recommended*

This CVP proposes the provision of a solar PV starter pack worth £10,000 through an expert partner, alongside a bespoke educational programme to engage students in decarbonisation and Science, Technology, Engineering and Maths (STEM) pathways. This package, which would be funded by WPD's shareholders, would result in immediate benefits for schools arising from energy savings. The cost of this proposal is £540k for 45 schools each year, totalling to £2.7m, with an estimated net benefit (financial and societal) of £23m on a 10 year basis.

The Challenge Group recognises the challenges of engaging areas with high level of economic deprivation in the transition to a low carbon economy. However, we were unclear whether this was a legitimate activity for a DNO to undertake and for network customers to pay for. WPD's justification is that they have proven expertise in: targeting areas of need; arranging installation; and delivering educational programmes in other areas. This may support the fact that it can do it but we question whether this amounts to saying that WPD should pursue it.

Furthermore, we question whether the provision of solar panels to schools is the best way to meet this challenge and would have liked to have seen alternatives, such as energy efficiency, considered. We are also concerned that the claimed benefits, which are primarily social, seem disproportionate to the costs for this relatively small-scale project.

The assumptions about the tangible savings that could be generated for schools look reasonable. However, as far as we could see, a significant proportion of the £23m is driven by the assumed value of the educational benefit. The claim of 'shareholder funding' is again complicated here by being part of a CVP reward that could generate significantly greater benefits than the costs (even if the costs are not re-couped). As a result of these concerns, we do not support this activity as a CVP.

*CVP5: Bespoke smart energy plans – partial support*

WPD propose offering 600,000 PSR customers a biennial 'bespoke smart energy plan'. The cost of this programme would be £5.0m, with a net social value delivered estimated £7.1m over a ten year period.

They assume that, of the 600k customers offered these plans each year by phone, there will be follow-up referrals for 5% in years 1 and 2, and 10% from year 3. They assume that these referrals lead to £14 of financial savings per customer. They also say that they have reduced the total claimed benefits by £12m following our challenge on the draft plan: they have now assumed that only 48% of people make behavioural changes after this type of advice (based on evidence of what happened in a similar situation) rather than the 100% originally assumed. WPD have also removed from the value calculation the financial 'benefit' of having a smart meter fitted.

The assumptions now look more reasonable – and this type of tailored advice, with a focus on driving behavioural change, could be valuable. Overall, we offer qualified support for this proposal as a CVP. However, despite WPD's strong track record of delivery in other areas of service delivery, we think any award should be contingent on real-world tests showing that the assumptions of take-up and benefits are realistic in practice.

*CVP6: £1m 'Community Matters' support fund – not recommended*

WPD are proposing £1m shareholder funding plus 1,000 staff volunteering days to 'achieve positive community outcomes in relation to vulnerability, environment and education'. The estimated cost of the CVP is £5.8m, with a £16.7m net social value.

This is positioned as part of its work to be a 'socially responsible business'. This programme would clearly be valuable if it was genuinely an altruistic and self-funded programme. But we think that there is a fundamental problem with wrapping up this type of 'responsible business' claim in an incentive scheme that delivers significant financial rewards to the DNO, paid for by customers. As a result, we do not support it as a CVP.

## 8.6 Finance

WPD have commissioned a report from Frontier Economics to update their views on the cost of capital and, as a result, made a welcome reduction in its proposed cost of equity from 5.8% to 4.96%. They have also, as we suggested, made some improvements to the clarity of the reporting of their results, although there remain important omissions.

WPD target a Baa1/BBB+ rating in the base case for both the Notional and Actual Companies. Ofgem is clear that it considers it is for individual DNOs to determine their target ratings. We accept that there are uncertainties which may make it desirable to target a rating which is above the minimum required to retain investment grade status but we also think it important that, at a time of financial stringency, consumers are not impacted by excessively high target ratings for either the Notional or the Actual Company. We regard Baa1/BBB+ as at the upper end of the acceptable target range and certainly do not consider that a company needs to demonstrate an expectation of that rating in order to be considered financeable.

The SSMD requires companies to submit the results of a series of stress tests on a base case for both the Notional and the Actual Company which incorporates the Ofgem W/As. Although Appendix SA09-A01 shows base case output for both the Notional and the Actual Companies, the results of stress testing are shown only for the Notional Company. (Appendix SA01-A02, which shows results for the Actual Company, is based on WPD's own assumptions for the cost of capital and, in any case, only shows the results of one sensitivity – downside RoRE. Appendix SA09-03, which gives the results of stochastic risk analysis prepared for WPD by NERA, is not based on the Ofgem stress testing requirement.) It is true that an important part of the focus of the price control is the financeability of the Notional Companies but the BPG contains a clear requirement to show the results of Ofgem's stress tests on both the Notional and the Actual Company. For comparative purposes, both are important. We do not understand why WPD have chosen to interpret the BPG in this way. As a result of this shortcoming, their commentary on stress testing is confined (unhelpfully) to brief remarks about the impacts on the Notional Company.

The Base Case modelling shows that, on the basis of Ofgem's W/As, all four of WPD's licensees are likely to achieve a rating in the Baa2-Baa1 range. This may well, as WPD states, be below their 'stated ratio target' but does not make any of the licensees unfinanceable on the basis of

Ofgem's W/As. The results presented show all the licensees under stress in the most extreme downside case (low RoRE performance), but we do not consider that they are so far from achieving investment grade status that they should be regarded as unfinanceable for the purposes of the price control. This is particularly so if the impact of Ofgem's proposed mitigating measures were more fully explored and a range of such measures proposed. It would have been easier to determine how far the four licensees are from achieving acceptable levels of financeability if WPD had presented a full set of results for the Actual Company and some analysis of those results.

Although WPD propose a cost of equity allowance which, at 4.96%, is significantly lower than that proposed in their draft plan, we are not persuaded that an allowance at that level is in the best interests of consumers or necessary to achieve financeability. We note that even the low RoRE stress test results for a case based on 4.96% are supportive of an acceptable rating, and that this is only just over 30 basis points below Ofgem's 'expected' rate. We do not, therefore, consider that financeability on the basis of Ofgem's W/As is unachievable for WPD. Instead, we consider that WPD need to further explore mitigating measures, including (if necessary) dividend restraint.

We discuss elsewhere the question of the appropriateness – or otherwise – of the various requests for higher cost of equity allowances across the suite of BP submissions. We comment in that context on the updated assessment of Ofgem's W/As by Frontier Economics which WPD presented with their plan.

It is clear from WPD's BP that they have given some consideration to Ofgem's proposed 'levers' for improving financeability. Although the Ofgem base case is modelled on the basis of WPD's 'natural' capitalisation rates which are in the 77.5-81% range for the four licensees, it proposes to use a lower rate (75%) to aid financeability, which we regard as helpful. The company have considered – and rejected – a change to the depreciation period and comments that it believes that Ofgem should set other parameters at a level which makes it unnecessary to make changes to depreciation periods to achieve financeability. WPD are supportive of Ofgem's proposal for a reduction in gearing from ED1 to 60% but, if they have made a full and exhaustive analysis of alternative levels of gearing and other mitigating measures, there is little evidence of it in the text of the BP. WPD's modelling demonstrates a requirement for significant new equity but their intentions in that respect are not made clear in the text and importantly, they do not make any explicit proposals in relation to dividend restraint (although we note that their plan provides for the payment of dividends totalling in excess of £1bn).

Under the heading 'Our plan is financeable' WPD's Board Assurance Statement contains an explicit statement that that is not the case: '…we do not consider that Ofgem's working assumptions are acceptable and therefore cannot provide assurance that our licensees are financeable under these assumptions'. We comment above that, although insufficient information has been presented for us to provide a definitive comment, it is our view that, with appropriate exploration and adoption of mitigating measures (particularly dividend restraint), the plan is financeable on the basis of Ofgem's W/As.

# Appendix 1: The Role of the Challenge Group

## (i) Purpose

The RIIO-ED2 Challenge Group was established by Ofgem in September 2020 with the objective of providing effective challenge, to the energy network companies and to Ofgem, on behalf of existing and future consumers. It was intended that we should strengthen the voice of consumers in the price control process by providing an independent challenge to, and scrutiny of, the Business Plans to be developed by the network companies. Our Terms of Reference require us to help to ensure that the distribution network companies deliver value for money services which current and future consumers want and need, with a particular focus on affordability, the protection of consumers in vulnerable circumstances and on sustainability, including the Net Zero transition and impact on the environment. As part of our primary purpose, the Group is expected to participate in the open public hearings in March 2022 and to review Ofgem's Draft Determination in the summer of 2022. As required by our Terms of Reference, the primary output from our work is this independent report for Ofgem, which contains our review of each company's Business Plan and overarching commentary on common themes, together with key issues which we believe should be interrogated in the Open Hearings in March 2022.

The Group consists of ten members, two appointed by Ofgem to represent specific organisations and the others appointed following an open recruitment process using a recruitment agency focussing on specific expertise. The current members are Roger Witcomb (Chair), Clare Potter (Deputy Chair), James Richardson (National Infrastructure Commission), Andy Manning (Citizens' Advice), Goran Strbac, Robert Hull, Joanna Hubbard, Helen Parker, Rosamund Blomfield-Smith and Stuart Bailey.[24]

The Group has Terms of Reference[25] which are available on Ofgem's website. As per our Terms of Reference, we are accountable, to the extent appropriate taking account of our independent status and in accordance with these terms of reference, to the Senior Responsible Officer of the RIIO-ED2 price controls (Steven McMahon). We have also published our forward work plan on the Ofgem website.

We established three sub-groups to ensure that the specialist expertise of individual members of the Group was brought to bear on the corresponding area of the BPs. These sub-groups covered:

- costs, Net Zero scenarios, engineering and asset health, and DSO and whole system;
- outputs, including environmental, provision for vulnerable consumers and reliability; and,
- financeability of the business plans.

The Group has met regularly in plenary session and there have also been numerous meetings of sub-groups and between sub-groups. We have also met with Ofgem personnel providing technical support to us.

We are grateful for the help we have received from Ofgem on technical support, matters of factual accuracy and regulatory procedure. The Challenge Group is independent of Ofgem. The views

[24] Members' biographies can be found here.
[25] Terms of Reference of the RIIOED-2 Challenge Group can be found here.

expressed in this Report are those of the Group and are not attributable to Ofgem, whose own assessment of the Business Plans will be reflected in its Final Determinations for RIIO-ED2.

We are also grateful for the strong and committed support provided by our secretariat function with technical and administrative support from Ofgem personnel as necessary.

## (ii) Our engagement with Ofgem to challenge its policy thinking

As set out in our Terms of Reference, an important part of our role is to review the Draft Determinations published by Ofgem in summer 2022, and as part of the broader consultation on these, challenge and advise Ofgem if any aspects of these determinations may not be in accordance with the RIIO-ED2 Objective. Ofgem have stated it will take into account our views before setting final determinations later in 2022.

## (iii) Our approach to engagement with the companies and their enhanced engagement groups

Our engagement with the companies has been with a view to ensure that the final plans submitted on 1 December 2021 to Ofgem fulfilled the requirements set out in our Terms of Reference. We held meetings with the companies during the plan preparation phase and provided feedback on their draft plans submitted in July 2021. Our comments, observations, challenge and feedback to the network companies on their plans were advisory but we have made clear from the outset that we expect our report to Ofgem, with our views on the engagement of the companies with us and on quality of the business plans, to inform Ofgem's assessment of business plans.

We also felt it important, and found it to be very useful, to engage regularly with the independent Customer Engagement Groups (CEG) established by each company. Our Chair and other group members of the Challenge Group have regularly met the Chairs of the CEGs through the quarterly meetings organised by Ofgem. We have also maintained contact through structured monthly telephone calls between a member from our group allocated to each company and the Chair of the relevant CEG. We also invited the Chairs of the CEGs (along with any relevant members) to attend all our meetings with the companies.

We are grateful in particular to the Chairs of the Customer Engagement Groups for their engagement with us throughout the process to date.

# Appendix 2: Glossary

| | |
|---|---|
| BAU | Business as usual |
| BMCS | Broad Measure of Customer Service |
| BP | Business Plan (final plan submitted by DNOs in December 2021) |
| BPDT | Business Plan Data Templates |
| BPG | Business Plan Guidance |
| CAI | Closely Associated Indirect costs |
| Capex | Capital expenditure |
| CAPM | Capital Asset Pricing Model |
| CBA | Cost-benefit analysis |
| CEG | Consumer Engagement Group |
| CI | Customer interruptions |
| CMA | Competition and Markets Authority |
| CMI | Customer minutes lost |
| CPI | Consumer Prices Index |
| CPIH | Consumer Prices Index inc. owner-occupied housing costs |
| DFES | Distribution Future Energy Scenario |
| DNO | Distribution Network Operator |
| DSO | Distribution System Operator |
| EAP | Environment Action Plan |
| EJP | Engineering Justification Proposal |
| ENWL | Electricity North West Ltd |
| ESO | National Grid Electricity System Operator |
| EV | Electric vehicle |
| FD | Ofgem’s Final Determination |
| FES | Future Energy Scenario |
| GD&T | Gas Distribution and Transmission |
| HV | High voltage |

| | |
|---|---|
| ICE | Internal combustion engine |
| IIS | Interruption Incentive Scheme |
| ILD | Index-linked debt |
| IT | Information technology |
| LA | Local authority |
| LAEP | Local area energy plan |
| LRE | Load-related expenditure |
| LV | Low voltage |
| NARM | Network asset risk metric |
| NIA | Network Innovation Allowance |
| NLRE | Non-load-related expenditure |
| NPg | Northern Powergrid |
| OE | Ongoing efficiency |
| Opex | Operational expenditure |
| OW | Outperformance wedge |
| PSR | Priority Services Register |
| RAG | Red, amber, green |
| RAV | Regulatory Asset Value |
| RoRE | Return on Regulatory Equity |
| RPE | Real price effects |
| RPI | Retail Prices Index |
| SBT | Science Based Target |
| SBTi | Science Based Target Initiative |
| $SF_6$ | Sulphur hexafluoride gas |
| SPEN | Scottish Power Energy Networks |
| SROI | Social return on investment |
| SSEN | Scottish and Southern Energy Networks |
| SSMD | Sector Specific Methodology Decision |
| Totex | Total expenditure |

| | |
|---|---|
| UKPN | UK Power Networks |
| UM | Uncertainty mechanism |
| W/A | Ofgem working assumption |
| WPD | Western Power Distribution |