Feedback on draft business plan: SPEN

The RIIO-2 Challenge Group has been established by Ofgem as part of the RIIO-2 enhanced engagement process, in order to strengthen the voice of current and future consumers in network price controls. The Challenge Group's objective is to provide an independent challenge to ensure that regulated network companies deliver the value-for-money services that are needed, with particular regard to affordability, the protection of vulnerable consumers, and the transition to Net Zero.

As part of this role, Ofgem has asked the Challenge Group to provide scrutiny of all draft business plans submitted by network companies in the course of RIIO-ED2. Our feedback on the draft business plan that you submitted on 1 July 2021 follows below.

The Challenge Group recognises the challenging nature of the work that the DNOs are being asked to carry out during the period of RIIO-ED2, and its crucial importance. In what follows, as per our remit, we have generally focussed on areas where we feel there is room for improvement. This is not to detract from the standard of your planning and its broader implications. Where we focus on affordability, we recognise that other disadvantages may be at stake if the networks are not upgraded as required, and where we focus on your environmental impacts, we recognise that other environmental benefits may be enabled by those upgrades. Nonetheless, affordability and sustainability remain vital considerations. The Challenge Group is keen that no contradiction should be seen between a business plan that meets the coming challenges and one that provides value-for-money, mitigates environmental impacts and supports vulnerable consumers.

Our feedback focuses on three areas:

1. Costs, scenarios, and DSO and whole system proposals
2. Outputs:
   i. EAP
   ii. Vulnerability strategy
   iii. Reliability
3. Finance

We expect this feedback to be reflected in the final business plan submitted on 1 December 2021.

1. Costs, scenarios, and DSO and whole system proposals

This note summarises our initial comments. Additional detail is provided in a supporting annex.

1. *ED1 Track record*

You are forecasting a 3% totex overspend for ED1 and that output targets will be met or exceeded. Asset heath delivery is on track. ED1 demand was below forecast. You have provided information on demand and network utilisation parameters to show the expected network capacity position at the start of ED2.

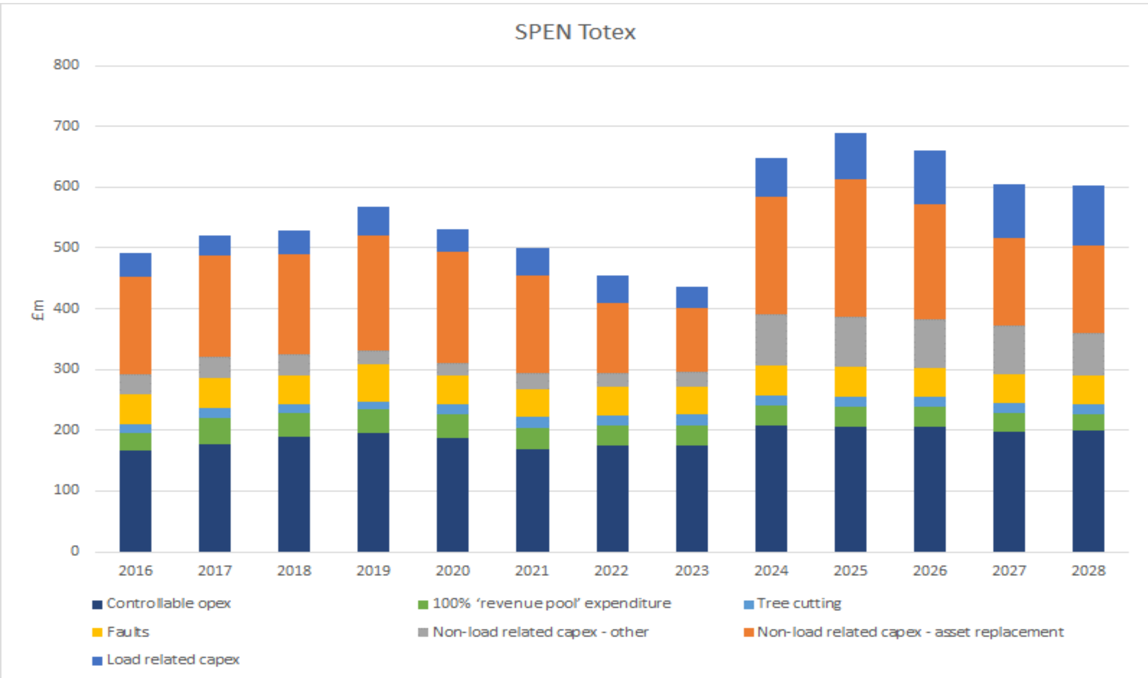
2. Scenarios and forecasts

Your baseline scenario LRE assumptions appear to be Net Zero compliant, which is welcome. You suggest that your baseline scenario is at the lower end of possible outcomes, and this is used to justify the use of uncertainty mechanisms from this level. However, our analysis suggests that your baseline case is consistent with ESO demand forecasts but forecasts for heat pumps appear to be higher than might be anticipated from common industry scenarios.

For your final plan. we would welcome clarification about how the demand and LCT forecasts have been derived, how they have been applied in the plan's LRE assumptions and a clear demonstration of consistency with common industry scenarios.

3. Totex overview (£3205m)[1]

We have reviewed your totex data submitted in your Business Plan Data Tables (BPDTs). Your baseline totex proposal for ED2 represents a 27% increase over average annual ED1 expenditure. A profile of the overall totex plan and main expenditure categories is shown below, showing a significant increase at the start of ED2.



[1] All totex figures quoted (unless otherwise stated) have been taken from the equivalent company PCFM or BPDT submissions for consistency. This may result in differences with numbers quoted in business plans – for example SPEN's business plan quotes a totex figure of £3234m. We have not attempted to reconcile these differences or differences between company assumptions at this stage.

The following table compares the changes in the main totex cost categories in company plans between ED-1 and ED2. These cost categories are reviewed further below. While we think the following comparisons are representative, we have observed some inconsistencies in assumptions used in supporting data tables for DNO ED-1 track records and ED-2 baseline totex bids. For final plans we would request that the bids for the baseline totex (within the price control) are clear and are based on consistent assumptions so that we may assess proposed changes with ED-1, and between DNOs.

	ED-1 Average Totex	ED-2 Average Totex	% change	LR Capex	NLR capex - assets	NLR capex - other	Opex
ENWL	259	400	54%	180%	68%	124%	24%
SPEN	504	641	27%	107%	15%	188%	7%
SSEN	573	826	44%	152%	62%	150%	13%
WPD	1050	1332	27%	134%	15%	118%	6%
UKPN	831	869	5%	27%	5%	48%	-4%
NPg	470	641	36%	351%	12%	100%	10%
Total	3686	4709	28%	128%	24%	110%	6%

a) *Load related expenditure (LRE): £416m*

Your average annual LRE is expected to increase by 107% between ED1 and ED2, with the largest increases in connections and secondary networks. You have described the linkage between scenarios, the forecast demand and the baseline investment plans, which is helpful. We would like additional clarification about what investment is included in baseline and upper view and in uncertainty mechanisms, and the reasons for prioritising expenditure at the start of ED2. Also, for your final plan, we would like to see justifications why additional LRE is required during ED2 given that your peak demand by 2028 appears not to reach your historic levels.

b) *Non-load related capex – assets: £895m*

This cost category increases by around 15% between ED1 and ED2. Asset replacement expenditure is forecast to increase by 12%. We are concerned that the ED2 increase is due to asset replacement expenditure being deferred to ED2 and customers having to pay twice for the same replacement work. Overall, we do not think non-load-related assets expenditure increases for ED2 have been justified given that asset health targets are being maintained on largely the same asset base as for ED1. We would expect these costs to remain stable or reduce as efficiency savings are applied. In your final plan we would like to see clear evidence for any expected change in asset health risk and associated expenditure.

c) *Non-load related capex – other: £396m*

This cost category increases by around 188% between ED1 and ED2, due to significant increases in IT and telecoms expenditures. While we welcome expenditure that delivers enhanced network visibility and flexibility, forecast benefits from flexibility appear low. We would like to see investment justifications including evidence that benefits will be delivered from this increased investment.

d) Opex[2] and efficiency: £1339m

You forecast a 7% increase in operating costs between ED1 and ED2 (including network operating costs, business support and closely associated indirects). Justifications for these increases are high level and we are concerned that efficiency opportunities have not been sought. We suggest you consider opportunities to hold these costs flat during ED2.
A 0.3% ongoing efficiency challenge has been included which we suggest should be increased to the 1-1.2% levels as for the 2020 RIIO-2 price control decisions.

4. Uncertainty mechanisms

You have proposed bespoke uncertainty mechanisms to address uncertain LRE and PCB removal. We agree that it could be appropriate to include LRE uncertainty mechanisms but would like to see evidence that these are appropriately calibrated in terms of costs, volumes and triggers, and do not provide windfall gains for companies. We think PCB removal is an issue that is best managed by the company and not passed to consumers. For your final plan we would like to see evidence to support the calibration of proposed uncertainty mechanisms including the baseline totex assumptions.

5. DSO and digitalisation

You are proposing to spend £123m on DSO activities in ED2 compared to £6m for ED1 and are targeting 19% of secondary substations to have metering installed. Your DSO and digitalisation plans are high level with limited evidence to give confidence that the plan and associated benefits can be delivered. You claim they will be substantially exceeding baseline requirements for these activities, but it is not evident how this baseline has been derived or the results measured, so this evaluation may be overly optimistic.

We welcome the initiatives that you are planning for digitalisation and DSO but 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. We suggest that the enabling technologies and processes should be further considered.

Overall in your final plan, we would like to see a clear justification for costs and benefits associated with your DSO and enabling investments. This should include benefits from distributed energy resources to enhance resilience, from active network management, and from interaction with the ESO.

6. Whole system

Your whole system plan remains to be completed by the final plan submission but a strategy has been defined. Overall, while we welcome that this statement of ambition extends beyond electricity networks, there is little evidence of the planned activities and benefits.

[2] Opex includes tree cutting, faults, revenue pool expenditure and controllable opex.

2.i. EAP

In reviewing the environmental commitments and EAPs in all the draft plans we have focused on decarbonisation. 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.

Overall, the EAP shows a considerable attention to detail and a coherent overall vision and strategy. You set out a clear and convincing view of your plan to decarbonise the network, and your claim to go beyond Ofgem's baseline expectations is for the most part convincing.

In setting your SBT, you have generally set out a reasonable level of detail and justification on how you plan to reduce you BCF, including breakdowns of current and past emissions from various sources. You use this to set an ambitious target for scope 1 and 2 emissions excluding losses, backed up with a long-term ambition to be carbon neutral by 2030 and to reach net zero by 2040. You claim that these targets go beyond the 4.2% annual reduction required by the SBT. We note, however, that the reductions required for a 1.5 degree trajectory can range from 4.2 to 6% and the SBTi advocates using the most ambitious scenarios.

Your target of a 10% reduction in SF_6 leaks is relatively unambitious. This may be justifiable given low leakage levels during ED1. You provide a reasonable level of detail on possible approaches to leakage and bank reduction and a good rationale for your decision, backed up with stakeholder engagement. However, we think that there remains room for more ambition so more quantification and justification of expected benefits of actions would be helpful.

On losses, your target to avoid 33GWh of losses over the course of ED2, considered as a proportion of total units delivered, represents a middling level of ambition. Given that your proportional losses have been the highest to date in ED1 it would be good to see the quantification and justification of actions and benefits set out more clearly.

On embodied carbon, you set out a clear and reasonably ambitious timeline for introducing a target on embodied carbon. You aim to have a measurement tool in place by 2023, to have set a baseline and target by 2025, and for that target to be met by 2028. We would suggest that the baselining and target-setting could perhaps be accelerated to 2024, but this timeline appears broadly appropriate. You have also done good preparatory work using the PAS2080 standard on carbon management in infrastructure, which you plan to apply to both your own carbon management and your supply chain.

In regard to your proposed CVPs, whilst we are supportive of the idea of targeting actual reductions in scope 3 emissions we do not think that this justifies a CVP reward as we judge this would be a reasonable part of BAU given Ofgem's expectations. On your proposal for a 'Mobile Asset Assessment Vehicle', we think that the benefits over and above losses reduction need to be clearly articulated.

Questions and challenges

- Overarching challenge: please ensure that ED1 performance, proposed actions and benefits are expressed as clearly as possible, in consistent units (ideally both in absolute and percentage terms) and that baselines are identified and justified.
- Your SBT trajectory has been calculated using 2018/19 rather than 2019/20 as the baseline year. We note with concern that due to a reduction in your BCF between these years, your overall emissions targets are roughly 40% higher than they would otherwise have been. According to the graph of your expected emissions that you provide in figure 31, the SBT trajectory seems to provide little challenge. Under these circumstances, we would strongly encourage you to update the baseline year and/or to adopt a steeper SBT trajectory. As noted above, the SBTi mandates a trajectory in the 4.2-6% range, and advocates using the most ambitious scenario possible.

2.ii. Vulnerability strategy

We welcome the following points about your vulnerability strategy.

- It commits to retest priorities with customers and stakeholders annually and to present the findings from this and resulting action plan to an independent external group.
- It is transparent in setting out your current PSR reach across different needs codes, and acknowledges that there are other important vulnerabilities not captured by the current codes which you intend to target.
- The strategy includes an interesting and developed approach to how you will use data to identify and target people most likely to face barriers in accessing LCTs.
- It has a clear approach to how different customers with different needs will be treated.
- It has a rigorous approach to governance, especially through your ‘coalition of partnerships’.
- It commits to benchmark your service annually (with an ambition to achieve international standards and score in Top 5 UK companies).

Questions and challenges:

The main themes of our questions and challenges are that your final plan should:

- Do more to define and measure the outcomes that you are aiming to achieve with your activities in this area
- Provide a detailed plan for how you will deliver your strategy, particularly when you are committing to a significant increase in activity
- Set out a clear justification for why you, as a DNO, are best placed to deliver your proposed activities.

- PSR reach: We want to compare the reach of DNOs’ PSRs on a like for like basis. By ‘reach’ we mean the proportion of all and eligible customers who are registered. We are therefore asking all DNOs to clarify:
    - Your current (ED1 actual) and targeted (for ED2) reach as a percentage of all customers.

    - Your current and targeted reach as a percentage of eligible customers (i.e. all those who fall into any of the MDD PSR needs codes).
    - A breakdown of the percentage of eligible customers registered by each needs code.
    - If you use a definition of eligibility other than the full set of needs codes, please explain what this is, why you use it, and what your current and targeted reach is as a percentage of this group of eligible customers.

  Throughout, please be clear whether you are talking about individual customers or households, and what multiplication factor you are using if relevant. Please also give details of any customer groups that you define as ‘high priority’ and the reasons for this prioritisation. To what extent and in what way will your PSR recruitment be targeted on high priority groups?
- PSR quality: When you contact customers in an attempt to keep the PSR up to date, how do you currently assess the effectiveness of this activity and its impact on data quality? You say you aim to achieve 60% ‘fully validated data’. How do you define data that is ‘fully validated’ and what is the comparable figure for ED1? What other criteria, if any, do you use to ‘cleanse’ PSR data and to remove people from the register?
- Impact of your support during a power cut: your commitment is for no less than 99% of needs to be met during a power cut? How do you measure this and what is your current performance by this measure? Are there any specific deliverables required? In what ways will the ED2 services that you offer to customers during a power cut be targeted on people with different needs?
- Partnerships: How will you assess the effectiveness of your more proactive ‘Coalition of Partnerships’ model?
- Fuel poverty:
    - You are proposing to support 40k customers in fuel poverty in ED2 compared with c5k in ED1. What evidence do you have (for example, from tests or trials) that this increase is deliverable?
    - You have estimated the value of your fuel poor support at £28m and various levels of information and advice on the energy transition at £10m. Set out the assumptions you have made to come to these estimates. What plans do you have to measure the actual benefits that customers achieve as a result of this support?
- Culture: How will you measure whether you are being successful in embedding a culture of understanding and responding to the needs of consumers in vulnerable circumstances across the business? In terms of the training you propose, how will you measure its impact or success?
- Costs: Please clarify: your total expenditure on vulnerability-related activities in ED1 (including any costs that are ‘funded’ by shareholders) with a breakdown by the main areas of activity. Please do the same for your proposed expenditure in ED2.
- CVPs:
    - Regarding the proposed CVP on supporting disadvantaged customers:
        - Your estimated savings are based on lab tests of the technology. What trials have you done to understand the in-home experience of this technology and what real world savings are achieved?
        - How confident are you in the lifetime of this technology?
        - How scalable is this approach – i.e. are you testing something that you could roll out?

- Regarding the proposed CVP on targeting vulnerable customers without a smart meter, given that we have a supplier-led Smart roll-out, how do you justify this being a legitimate role for a DNO, and how would it interact with the supplier obligation?

2.iii. Reliability

Your overall reliability performance has been in the middle of the pack during ED1, and your ED2 targets are likely to leave you in a similar place overall. You say your plans would leave customers '15% less likely' to have an interruption, with the 'average duration reduced by 10%'. In terms of WSC, you aim to leave 2,400 customers with one less power cut a year, with an hour less off supply.

Questions and challenges

- Customer interruptions (CI) and customer minutes lost (CML) targets: We are having difficulty reconciling the CI and CML commitments in your network performance strategy document with those in your strategic summary. Please can you explain how they reconcile or else which are correct. Are your headline commitments of 15% fewer interruptions and outages that are 10% shorter true for both networks? Please break them down if they are an average across both.
- Worst-served customers: can you explain your performance and targets here in absolute terms – i.e. what is the current experience in terms of number and length of outages for these customers and what would it be after your current plans are delivered?

3. Finance

We were pleased to note that the finance section of your Plan was in most respects compliant with the requirements set out by Ofgem in the Sector Specific Methodology (SSMD) and that you have carried out a full scenario analysis with the results clearly presented.

Although there are a number of positive aspects to your Plan, there are some important areas which we consider need attention before submission of your Final Business Plan (FBP):

- You have set out a strong rejection of the concept of the outperformance allowance. You should be aware that we concur with Ofgem's stance on outperformance which we consider to be very well supported by historic evidence. We expect to continue to be supportive of any measures which Ofgem decides to take to address this issue;
- You are targeting a rating of BBB+/Baa1 in the base case. As you will know, Ofgem takes the view that it is for individual DNOs to select their target rating, subject only to that rating never falling below investment grade (and now with arrangements that Ofgem must be alerted if there is an immediate risk that it falls below that level). As a licence requirement, that is clearly an important consideration. Ofgem obviously bases its assessment of the financeability of individual DNOs on their Notional Company but we consider it important, in the context of minimising costs to consumers, that Ofgem

is able to set its generic financeability parameters on the basis of a full understanding of the optimal financing arrangements for the Actual Companies also. In this context, we consider your target rating of BBB+/Baa1 to be at the upper end of the acceptable range;

- You point to a number of aspects of Ofgem's determination of the cost of capital for the sector which you regard as 'errors' and say that, in your view, a Cost of Equity allowance of 6.21% is required to 'reflect the risks faced by equity investors when investing in the electricity distribution sector'. We do not consider that the results you provide for your own companies, based on a 4.65% Cost of Equity allowance, support that statement: almost all your downside scenarios show a rating of A3/Baa1 and even in the worst downside cases (totex overspend and RoRE underperformance), you show a rating is Baa2 for both SPD and SPM. We note your comments about your 'probabilistic' analysis but also that there are a number of ways in which risk can be mitigated and that there is considerable scope for upside outcomes (see below on both counts). In the round, we see very little in the results of your scenario analysis to indicate that there is a risk of your rating falling below investment grade. We cannot see any basis for your proposal for a Cost of Equity allowance of 6.21% (which is at the higher end of those requested) or that it would be in the interest of consumers. We do not, in any case, support the concept that it is appropriate to change the Cost of Equity allowance to support the varying requests of, and issues relating to, different DNOs;
- We found the presentation of your results confusing. Companies are not penalised for proposing an alternative Cost of Equity allowance but it is important that results which are based on your proposed 6.21% Cost of Equity are appropriately distinguished from those based on Ofgem's W/As so that your FBP incorporates a clear and unambiguous assurance of financeability on the basis of Ofgem's W/As;
- You should be aware that we are supportive of Ofgem's proposed Cost of Capital allowances which we regard as based on sustainable Capital Asset Pricing Model analysis with appropriate cross-checking. The clear evidence of appetite for the acquisition of utility distribution companies – and at a very substantial premium to RAV - does not support an argument that Ofgem's analysis of the WACC appropriate to DNOs, and hence its Cost of Capital W/As, are miscalculated. We also consider that the extent to which expenditure in ED2 will be subject to adjustment arrangements (uncertainty mechanisms and other) and the escalation arrangements which Ofgem proposes in relation to the cost of both debt and, through adjustment of the risk free rate, equity, are indicative of a significant lowering of the risk profile for DNOs as against that in ED1. They are not, therefore, in our view, supportive of an increase in Ofgem's Cost of Capital allowances over those currently proposed;
- You say that you prefer not to adjust depreciation and capitalisation rates to help financeability and you have not shown the impact of doing this. We do not think this stance is necessarily optimal for consumers. You refer to an intention to consider changes to gearing and the capitalisation rate at 'final proposals'. We assume that this refers to your December FBP: if so, that would be helpful. You may need also to provide for dividend restraint/new equity to ensure that you can demonstrate your Plan is financeable on the basis of Ofgem's W/As;
- It is clearly for individual DNOs to determine their debt funding strategies and the extent to which they implement those strategies on a group-wide basis but you should be aware that we can see no reason for a small company premium in the Cost of Debt allowance.

Annex: assessment of costs, scenarios, and DSO and whole system proposals

This annex sets out our supporting comments on the SPEN July plan. In each of the following areas we have set out what we are looking for in each plan and our observations about the draft plan.

1. Scenarios and forecasts

We are seeking to understand how the companies have aligned their forecasts with Net Zero objectives, as set out in the FES and 6th Carbon Budget and take account of any local customer-led drivers. We wish to see how these forecasts lead to investment at different network voltages, including where flexibility resources will be used instead of investment.

We welcome that SPEN has considered three scenarios, each appear to be compliant with Net Zero, and has reconciled these with the ESO FES and CCC pathways. SPEN argues that the baseline scenario is at the lower end of net zero forecasts and represents the best approach for customers, assuming that Uncertainty Mechanisms for investment are in place.

By the end of ED-2, SPEN forecast they will connect

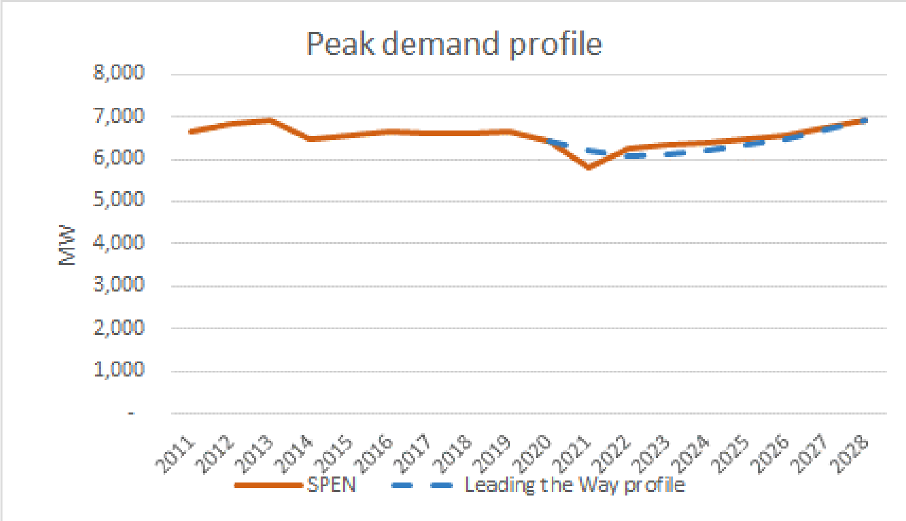
- 670,000 EV’s and 370,000 heat pumps by 2028 under their Baseline scenario and
- 1,020,000 EV’s and 630,000 heat pumps under their High scenario.

SPEN forecast that their peak demand in 2028 will be 6902 MW, compared with 6752 MW in 2021.

SPEN has around 11.4% of the Networks’ customer base. The forecast number of EVs across this customer base in 2028 is broadly in line with the ESO FES Consumer Transformation or Leading The Way scenario which forecast 7.7m BEVs (cars + vans) – these are not at the lower end of the EV uptake forecast by the ESO forecasts and form part of its justification for LRE Uncertainty Mechanisms.

Again, SPEN’s forecast for ASHPs, including hybrids, under their baseline scenario is consistent with the ESO FES Consumer Transformation or Leading The Way scenarios which are not at the lower end of ESO forecasts. We would welcome a clear explanation of this.

The SPEN submission of demand profiles in the BPDTs shows an increase of around 7% between 2020 to 2028. The following chart shows the relative forecasts with the ESO (Leading the Way) forecast, which they consider to be the most likely pathway to Net Zero targets, and the SPEN baseline forecast is consistent with this profile.

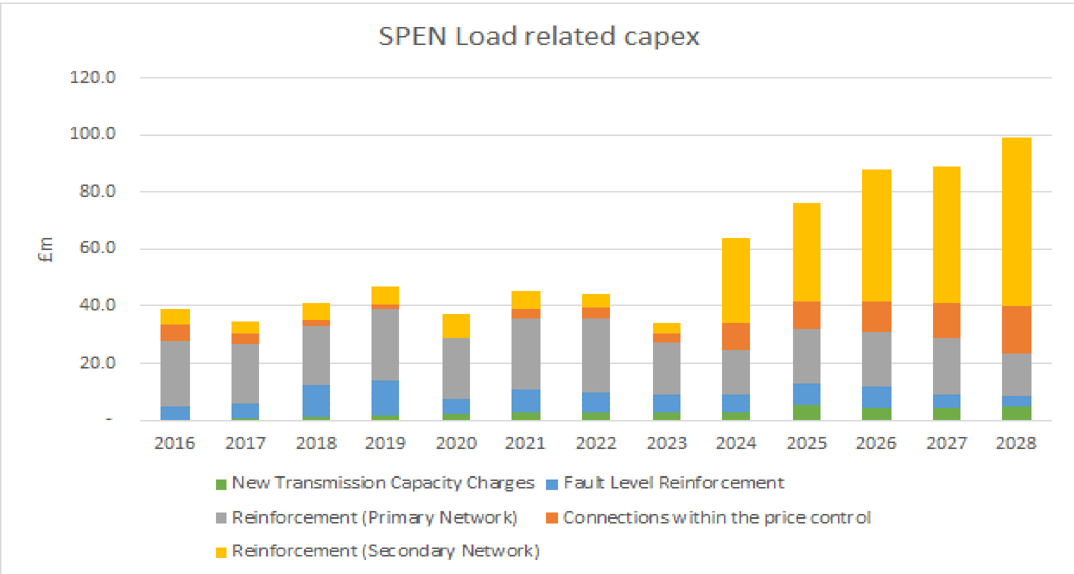


2. Totex - Load related capex

We are seeking to understand company investment pathways for load related expenditure, and how they have taken account of:

- Historic levels of network utilisation and reinforcement expenditure
- Downward cost drivers, including efficiencies, innovation and flexibility
- Upward cost drivers including demand scenarios and anticipatory investment

We are looking for evidence from EJPs and CBAs which justify costs, volumes and timings of expenditure together with uncertainty mechanisms where justified and PCDs to provide delivery certainty.



	ED2 £m	% change
Total load related capex	416	107%
Connections	58	281%
Primary reinforcement	89	-21%
Secondary reinforcement	218	669%
Fault levels	29	-25%

SPEN's baseline load related capex profile is shown in the above chart and table, totalling £416m in the ED2 period. SPEN's high forecast adds an additional £203m to this baseline. Given that your peak demand in 2028 seems to be reaching 2012 levels, we would welcome justification of the additional expenditure.

SPEN has provided a breakdown of the proposed unit costs and volumes of investments in looped cables, LV network and fault level investments to provide a path from the scenarios to the demand forecasts used to justify the levels of assumed investment at different voltages, and then to the investment profiles for the above categories.

There is evidence that flexibility and system losses are being considered in the EJPs. The investment profiles show a significant increase at the start of ED-2 which does not appear to be linked to the demand and network utilisation profiles. This may lead to inaccurate prioritisation of investment needs and consequent inefficiencies.

3. NLRE totex for ED2

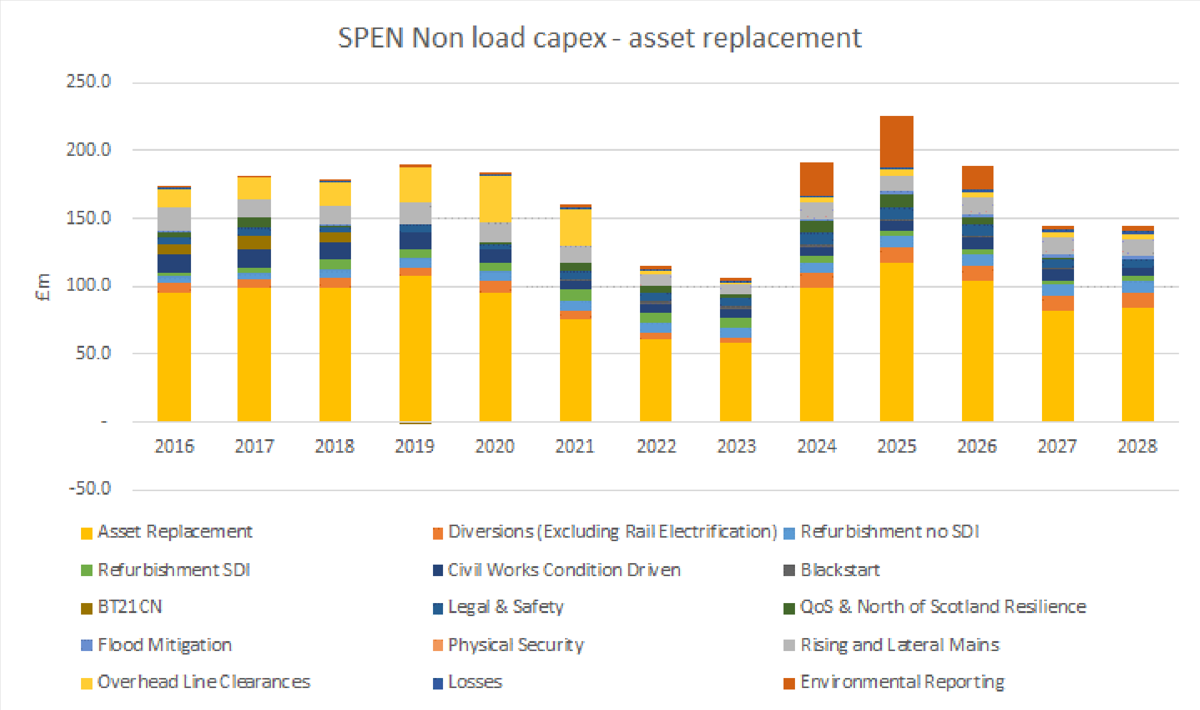
As in the case of LRE totex, we are seeking to understand company investment pathways for non-load related expenditure, and, again, how they have taken account of:

- Historic levels of non-load related expenditure, asset health and reliability levels
- Downward cost drivers, including efficiencies, intervention options, and innovation
- Upward cost drivers including demand scenarios and anticipatory investment

We are looking for evidence from EJPs and CBAs which justify costs, volumes and timings of baseline expenditure to deliver asset health and reliability outputs during ED2, including PCDs where appropriate to provide delivery certainty. We are also looking for evidence that, where a higher rating for a replacement asset is proposed, utilisation and load data is provided to justify this and that due consideration has been given to replacement vs refurbishment.

We have examined SPEN's proposals for a) NLRE - asset replacement and b) NLRE - other. The NLRE asset replacement profile is shown below, together with the major changes between average ED1 and ED2 expenditures.

NLRE – asset replacement

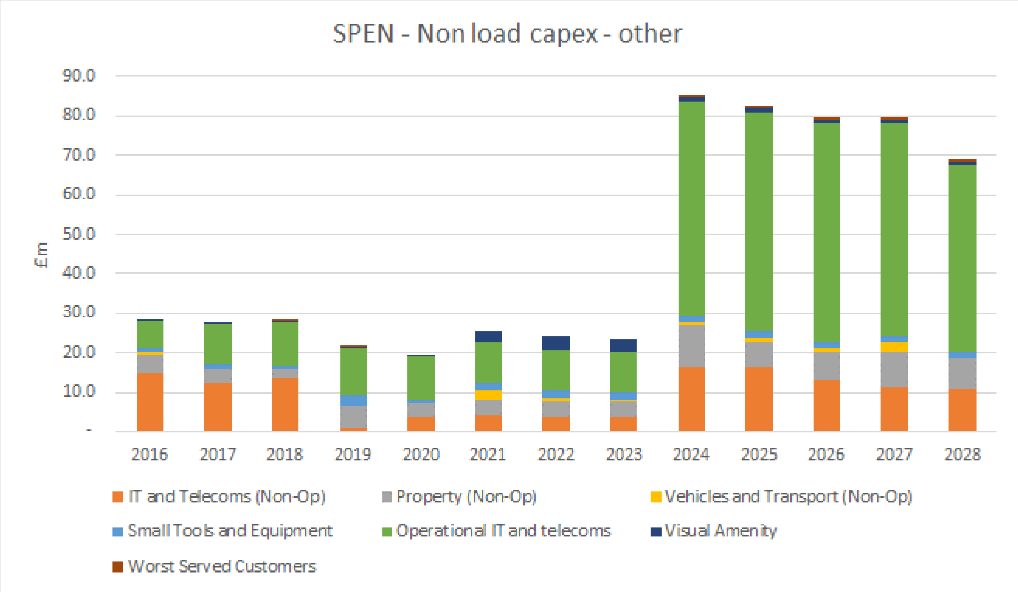


SPEN's plan appears to state (page 142) that NLRE is only increasing by 2% from ED-1 whereas the asset replacement capex described above shows an overall increase of 15%.

Overall, we do not think the expenditure increase for ED2 above that for ED1 has been justified. In particular, SPEN are continuing to maintain largely the same assets as ED1 and we would expect costs to remain stable or reduce as efficiency savings are applied. For asset health expenditure we would wish to see evidence to support any proposed change to intervention volumes and costs compared to ED1.

NLRE – other

The following chart shows the forecast profile for NLRE – other. There is an average increase of 188% from ED1 driven by significant increases in IT/telecoms.



We welcome additional expenditure where it delivers enhanced network visibility and flexibility markets. However, the above profile shows a sudden increase in expenditure in 2024. We would like to see evidence to demonstrate that this profile can be delivered, together with clear justifications that show how the overall DSO and other system benefits from these enhanced outputs are delivered efficiently.

4. Totex - Opex and efficiencies for ED2

SPEN's average operating costs increase by 7% overall for ED-2 compared with ED-1, with closely associated indirect costs increasing by 14%.

	ED2 £m	% change
Total Operating costs	1,497	7%
Network operating costs	464	2%
Closely associated Indirects	540	14%
Business support costs	335	7%

SPEN justify the increased engineering resource covered by this CAI increase due to the increased capital delivery programme across load and non-load programmes together with the need to develop enhanced network designs and DSO capabilities.

While explanations for cost increases are detailed, these are high level and we are concerned that efficiency opportunities have not been sought with corresponding rigour, and these costs may be overstated as a result.

Overall, SPEN have included embedded efficiencies in their plan together with a 0.3% pa ongoing efficiency challenge.

While the SPEN efficiency proposal is welcome, we think that this efficiency challenge should be set at levels equivalent to those proposed for electricity and gas transmission and gas distribution i.e. an ongoing efficiency challenge of 1.15% p.a for capex and 1.2% pa for opex.

We note that SPEN has set out its approach to determining unit costs in Annex 5A.5 Unit Cost Manual (UCM). SPEN has engaged with Arcadis to complete independent assurance of its UCM by testing the methodology, the reasonableness of individual costs, the accurate application of unit costs within BPDTs and validation of unit costs that are materially higher or lower than industry benchmark.

5. Bespoke uncertainty mechanisms

SPEN has provided details of its proposed approach to all Ofgem specified uncertainty mechanisms together with the following bespoke mechanism.

Category	Risk addressed	Mechanism	Potential cost
PCB	New legislation requires us to remove all oil filled assets with more than 50ppm PCBs by 2025. The extent of impact on our network may not be entirely clear at the start of RIIO-ED2 and we believe it is in the best interests of customers to propose a volume driver to manage costs in this area.	volume driver	£70.8m

For PCBs, SPEN have calculated the volumes of pole mounted transformers (PMTs) and the associated HV poles that must be replaced by 2025 to mitigate PCB contamination. Due to incomplete condition data, they consider there to be significant uncertainty about the required final level of interventions. They are proposing a volume driver to adjust allowances for the actual numbers of PMTs and poles replaced to mitigate potential PCB contamination.

While we agree that this issue must be addressed, we note that c£71m has already been include in ED-2 baseline expenditure for this purpose. We think this risk can be more effectively managed by SPEN as part of the overall NLRE expenditure, and that a specific volume driver where additional risk is passed to customers is not justified.

SPEN has also provided an update of proposals for a LRE uncertainty mechanism. They are working with Ofgem and other DNO's and expect to develop three different uncertainty mechanisms to manage general uncertainty within the load related plan. They propose:

- **Services volume driver:** This is to cover uncertainty in high-volume lower cost activity on upgrades to cable and terminations into customer properties. We expect this to be linked to the number of services replaced.
- **Secondary network capacity volume driver:** This is to cover uncertainty in high-volume lower cost activities on the lower voltages of network (LV and HV). We expect this to be based on both MW added and utilization of network.
- **Reopener (supported by Load index):** This is to cover uncertainty in low-volume higher cost activities on the higher voltage of the network (primary EHV and 132kV), where large variations in scale and cost of the projects make a volume driver unsuitable. This reopener should not simply be a continuation of the current RIIO-ED1 reopener, as this mechanism strongly disincentivises any investment over the baseline.

Overall, we welcome the limited number of bespoke mechanisms proposed by SPEN, and the intent to design a load related uncertainty mechanism, including the use of load index information. SPEN thinks that it will be highly likely that UMs will increase LRE over ED2 – we would welcome details of the analysis that underpins this statement.

In the final plan, we will want to be assured that any such mechanisms provide a fair balance of risk between consumers and company, and that risks fall where they can best be managed.

6. DSO and digitalisation

We are seeking to understand how DNO plans will demonstrate delivery of:

- Digitalisation, providing high visibility of network utilisation and available capacity
- DSO functions, especially for third party access to flexibility markets,

We are seeking to understand proposed costs and benefits from these DSO initiatives, including how this ambition exceeds business as usual expectations. These include benefits from working with the ESO.

<u>DSO and digitalisation</u>

SPEN set out the following parameters for their DSO activities:

- Network visibility - at end ED1, SPEN will have 3% of Secondary substations with demand monitoring and are targeting 19% by end of ED2. They will install 14,102 LV monitors.
- Flexibility markets – 291 MW pa procured over ED2 compared to ED1 forecast of 53 MW.
- Costs - SPEN's DSO data tables show expenditure of £6m for ED-1 and £123m for ED-2. The SPEN plan suggests that direct cost savings of up to £334m may be realised over 45 years by delivering 22 constraint management zones.

SPEN's plan proposes that they will invest £123m to deliver these DSO capabilities and meet the minimum requirements laid out by Ofgem. They propose initiatives for the following:

- Planning & network development – further develop forecasting tools and produce annual LTDS and DFES reports; install 14102 LV network monitors; enhance network modelling and monitoring; Introduce effective processes for sharing planning information, publish evidence on decision making, and establish a robust optioneering process.
- Network operation – network monitoring, forecasting platform development, work through ENA to co-ordinate DER providing flexibility, plus exchange of data with the ESO. Will roll out decision making framework and near-time forecasting platform; will test secondary trading arrangements.
- Market development – flexibility portal to be developed, data accessibility to be developed; report on conflicts of interest; publish relevant data to enable market participation and develop clear processes for securing flexibility resources from third parties.

SPEN claim that they will substantially be exceeding baseline for these activities, but it's not evident how this baseline has been derived or the results measured, so the performance evaluation appears overly optimistic.

The DSO expenditure shows a significant increase from ED1 levels. Overall, the DSO action plan appears relatively high level with most delivery dates to be confirmed, and the delivery of flexibility benefits are not well evidenced. We would also welcome evidence of customer/consumer benefits that go beyond flexibility.

DSO CVP – none provided

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, the SPEN digitalisation strategy is set out at a high level but the values ascribed to customer benefits are difficult to ascertain and delivery may be uncertain.

7. Whole system proposed strategy and ambition

We are seeking to understand the costs and benefits of whole system initiatives that companies plan to undertake in coordination with stakeholders across electricity and other sectors. We are seeking to understand how this exceeds business as usual benefits.

SPEN state in their plan that their Whole System journey is far from complete and that further work is required.

SPEN propose a Whole System strategy will be delivered through the adoption of a coordinated Whole System approach across their business. This will be embedded into their management and decision-making processes through the adoption of 4 Whole System pillars. These are:

- They will develop long-term collaborations with other parties, including with other energy companies, local authorities and devolved governments.
- They will deliver long-term value, based on investment appraisal, identification of risk, opportunities, and optimisation of the network.
- They will embed Whole System thinking at the core of every investment we make, using our partnerships to identify and deliver optimum solutions for consumers.
- They will use their innovation programme to push the boundaries of Whole Systems thinking.

This proposed approach is high level and appears to be little more than a statement of ambition rather than a plan to deliver benefits from whole system initiatives. Whilst it is clear that SPEN understands that Whole System goes beyond just electricity networks, there is little evidence of ambition and development of services that consider heat and transport, other than the provision of EV charging points. For example, whole electricity system innovations refers to Project Fusion which has already been delivered in ED1.

Whole system CVP – SPEN have proposed the following whole system CVP:

Whole system CVP	Proposal	Cost/benefit
CVP2: EV Optioneering – Our strategic role in accelerating the deployment of core EV infrastructure	This involves carrying out EV optioneering works for 35 local authorities. EV optioneering aims to identify the optimal placement of EV charging infrastructure, saving on connections costs, accelerating the EV infrastructure roll out and facilitating the uptake of electric vehicles	Costs: £4.1m Gross Benefit: £15.2m Potential CVP award: £5.7m

While it will be important to ensure that constraints to EV charging are addressed during ED2 as the number of charging points increases, these charge points connections are likely to be developed by a wide range of third parties and it's unclear why proposals to work solely with Local Authorities would provide additional benefits to customers. The availability of connection options for EV charging might be expected to be a business as usual service provided to all parties interested in such connections.