Feedback on draft business plan: NPg

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 0% totex overspend for ED1 and 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, highlighting that 88% of major substations will be less than 80% utilised.

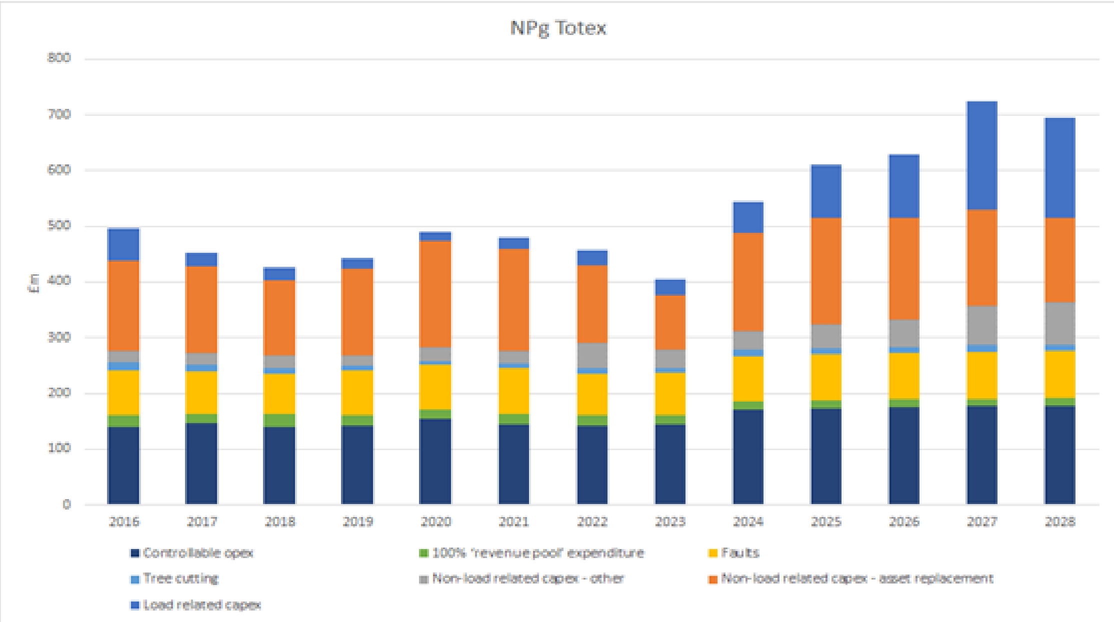
2. Scenarios and forecasts

Your baseline scenario appears to be Net Zero compliant which is welcome. You suggest that your baseline scenario is at the higher end of possible outcomes. Our analysis suggests that your baseline case is consistent with ESO demand forecasts but forecasts for EVs and heat pumps appear to be higher than might be anticipated.

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 the PCFM and BPDTs. Your baseline totex proposal for ED-2 represents a 36% increase over your average annual ED-1 expenditure. A profile of the overall totex plan and main expenditure categories is shown below, showing significant growth from the start of ED2.



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

[1] All totex figures quoted (unless otherwise stated) have been taken from the equivalent company BPDT or PCFM submissions for consistency. This may result in differences with numbers quoted in business plans. We have not attempted to reconcile these differences or differences between company assumptions at this stage.

(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): £643m (PCFM)*

Your average annual LRE is expected to increase by 351% between ED1 and ED2. We do not think this expenditure increase has been well justified. You state that you think this investment to meet Government targets for heat pumps and EVs, and even if the outturn is lower the assets will still be needed within 10 years. We are concerned that a high expenditure bid could either lead to windfall gains for the company, or nugatory investment due to inappropriate prioritisation. We would like to see the LRE justifications address potential downward cost drivers, such as network capacity headroom, network visibility, demand profiles and flexibility as well as upward drivers. 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: £871m (PCFM)*

This cost category increases by around 12% between ED1 and ED2. Overall, we do not think non-load-related assets expenditure increases for ED2 have been justified given that expenditure for asset health and items in this cost category is being maintained on largely the same asset base as for ED1. We would expect these costs to remain stable or potentially reduce as efficiency savings are applied and would like to see justification that the proposed investment increases are necessary. 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: £275m*

This cost category increases by around 100% 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: £1340m

You forecast a 10% 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 0.5% 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 expect Ofgem to develop an uncertainty mechanism for load related capex forecasts. 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. As above, we are concerned that the proposed baseline LRE forecast may be targeted higher than necessary if a LRE uncertainty mechanism is to be developed. 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 have proposed a DSO plan that appears to indicate limited expenditure increases over ED1, although a significant increase in LV monitoring and use of flexibility/curtailment resources is proposed. Your plan appears to indicate a step change in DSO activities and we would like to see evidence that this can be integrated with delivery of digitalisation. We find it difficult to understand the benefits that will be delivered as a result of these activities e.g. from consumer price signals, and how they will interact with proposed reinforcement plans.

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

You have set out whole system ambitions and outcomes in your plan. Overall, these appear to set out a high level ambition, without being specific about deliverables or benefits. We suggest that the plan should consider whole system actions which help to deliver benefits outside the NPg electricity system.

[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, we were slightly disappointed by the lack of articulated vision and longer term strategy in the EAP. There is an assessment framework in place and EAP actions are placed within the context of a risk assessment summarised in the EAP but it was not clear, for example, why embodied carbon and supply chain were shown as medium priority.

The evidence of use of engagement to inform options and actions is quite thin and not compelling (for example, was the contribution of supplier emissions to the BCF explained adequately, given that support for BCF reduction is high but for supplier emission reduction is low?).

You show minimal ambition on scope 3 emissions. You go no further than Ofgem's Baseline Expectation of reporting on them and although we recognise that inclusion of these in the SBT is optional the lack of proposed action shows disappointing lack of ambition. On SF_6 it would be helpful to understand why the performance across the two licence areas differs.

You do not set a target for losses. The only performance measures you suggest are fairly minimal and relate to process rather than outcomes. The Losses Strategy is detailed, but sometimes seems more concerned with justifying why action on losses is unviable than considering new options.

In relation to embodied carbon, you aim to have set a baseline by 2023/24, but do not set a date by which you will set a target for reduction. You do include a good level of detail on your planned approach to embodied carbon measurement.

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.
- What are the causes of relative performance on SF_6 leakage across the two licence areas? Can the level within NPgY be improved relative to NPgN and what would that do for overall target?
- In the losses strategy, can you set out the quantification and justification of actions and benefits more clearly?

2.ii. Vulnerability strategy

We welcome the following points about your vulnerability strategy.

- You have acted on the insight that many people don't identify as vulnerable or want to be on a 'register' by calling it a Priority Services 'Membership', emphasising the benefits on offer.
- It proposes a potentially welcome focus on targeting a big increase in PSR registrations among 'high risk' customers, although this is not yet fully explained.
- It proposes working on resilience planning with locations, such as care homes, that have many residents in vulnerable circumstances.
- It builds on current activity - for example, the approach on fuel poverty is to scale current activity across the whole region. This provides us with some confidence that the strategy is deliverable in practice.
- It contains specific commitments relating to actions taken during a power cut (for example, the roll-out of mobile batteries).
- It is transparent on costs and how they relate to different activities.

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.
    - You say you are aiming to recruit 'at least 70pc of eligible high risk customers by the end of ED2'. What do you mean by 'high risk' and how did you arrive at

this prioritisation? Are your PSR targets contingent on the CVP proposal for a ‘One-stop App’ being accepted? If the app was not accepted as a CVP, what would the impact be on your targets?

- 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, and how do you propose to measure this in ED2? What other criteria, if any, do you use to ‘cleanse’ PSR data and to remove people from the register? Please explain your current and targeted performance for any PSR quality measures that you use or plan to use.
- Impact of your support during a power cut: Other than the headline customer satisfaction metric, how do you currently measure the impact, reach and relevance of services that you provide to customers in vulnerable circumstances during a power cut? To what extent have you assessed any gaps between the specific needs of different groups of customers and the impact of the support that you offer? In what ways will the ED2 services that you offer to customers during a power cut be targeted on people with different needs?
- Fuel poverty: You say you will support 25% of customers in fuel poverty in ED2. How many customers is that each year compared with the 5k customers that you say you support in this way today? You have estimated the potential value of these initiatives. What plans do you have to measure the actual benefit achieved by customers?
- Direct support: You say you are aiming to ‘overcome barriers and directly support 5k vulnerable customers through the transition’ each year. What sorts of ‘direct support’ do you plan? You say you will use the innovation allowance to trial new approaches – have you done any tests or trials in ED1 to explore what type of support might be effective?
- 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?
- Bespoke outputs: We welcome the transparency and accountability of your proposal for a reputational incentive for an annual vulnerable customers delivery report. But we would question whether this reporting needs the special spotlight of a reputational incentive, when this could be part of BAU.
- CVPs:
    - Regarding your proposed CVP for a one-stop app for vulnerable customers, access for customers via a range of digital channels feels like business as usual in 2021. How do you justify it as being beyond BAU and the normal activities of a DNO?
    - What evidence do you have that this would be the best channel and solution for customers in vulnerable situations? How would you overcome barriers, for example around language, accessibility, digital exclusion?
    - Is this proposal supported by stakeholders with relevant expertise?

2.iii. Reliability

You have achieved your reliability targets in ED1 but still have among the poorest absolute performance compared with other DNOs. You are targeting a 12% reduction in the number of power cuts (CI) and a 25% reduction in their duration (CML). You also set out plans to reduce the number of longer power cuts, reducing outages that are longer than 12 hours by 50% and more than 6 hours by 15%.

Questions and challenges

- Customer interruptions (CI) and customer minutes lost (CML) targets: your targeted reduction in the number of power cuts would still leave you among the weaker DNO performers on this measure. How have you judged that this is the appropriate level of investment in this area compared with other investments you are prioritising in your plan?
- Worst-served customers: you say you will reduce the length of power cuts for your 2,400 worst-served customers 50%. 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 largely compliant with the requirements set out by Ofgem in the Sector Specific Methodology (SSMD) and that you have carried out, and presented with admirable clarity, the full scenario analysis requested.

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

- You express reservations about the concept of the outperformance allowance. You should be aware that we concur with Ofgem's stance on outperformance and that we consider it 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;
- Although you have assessed your Notional Company against a BBB+/Baa1 rating, you are alone among the DNOs in targeting a rating of A-/A3 for your Actual Company. It is clear from the results of your scenario analysis that, on the basis of the financing structure you propose, you could expect to retain that rating. As you will know, Ofgem takes the view that it is for individual DNOs to select their target rating, subject only to a licence requirement that that rating never falls below investment grade (and now with arrangements that Ofgem must be alerted if there is an immediate risk that it falls below that level). Because the maintenance of an investment grade rating is a licence requirement, the target rating of your Actual Company is clearly a significant 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 Actual Companies also. It is therefore important that both sets of projections are drawn up on the basis of minimising the impact of financing costs on consumers. In

that context, we regard even BBB+/Baa1 as at the upper end of the acceptable target range and that, overall and taking into consideration the cost of both debt and equity, a target of A-/A3 and 50% average gearing across your two DNOs is unlikely to be optimal in terms of financing costs;

- Although you say that your licencees would meet Ofgem's financeability assessment criteria, you do not provide a clear and unambiguous assurance of the financeability of your Plan on the basis of Ofgem's W/As. We consider that that will be necessary at the FBP stage. We do not consider that the results of your scenario analysis, carried out using Ofgem's W/As, support your suggestion that Ofgem's proposed Cost of Equity allowance is too low and that it needs to be in the 5.81-6.87% range. Such a change would not, in our view, be in the interest of consumers: you may wish to reconsider this proposal before submission of your FBP. As indicated above, we consider Ofgem's Cost of Equity allowance, to be applied to the sector as a whole, to be soundly researched and calculated. We do not think it appropriate that that calculation should be influenced by the varying requests of, and issues relating to, different DNOs;
- 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 (CAPM) 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 and are also not, in our view, supportive of an increase in Ofgem's Cost of Capital allowances over those currently proposed;
- You propose a very significant shortening of the depreciation period. Although we have urged companies to examine the impact of minor changes in capitalisation and depreciation rates to aid financeability and minimise costs to consumers, we consider that, even against the background of increasing change in the nature of your asset base, a shift of the magnitude you propose is excessive and is too far removed from the average economic life of your asset base. We note that you have not given consideration to alternative rates of capitalisation.

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

This annex sets out our supporting comments on the NPg 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 the wide range of scenarios that NPg has examined and note that it is using its ‘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.

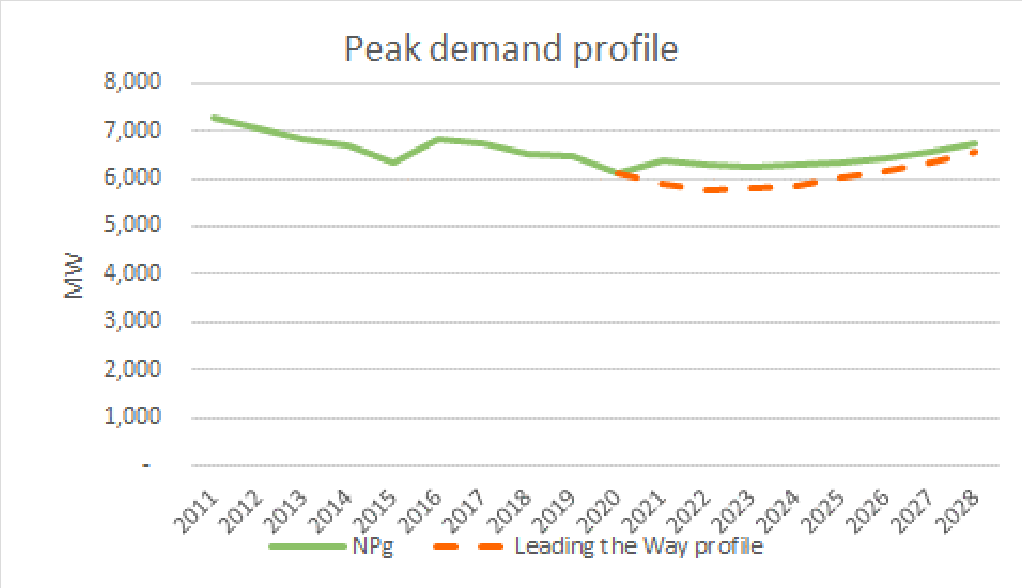
By the end of ED-2, NPg forecast they will connect

- 940,989 EV’s and 308,595 heat pumps by 2028 under their Planning scenario and
- 1,139,422 EV’s and 334,447 heat pumps under their Upper scenario.

NPg has around 13% of the Networks’ customer base. The forecast number of EVs in the Planning scenario 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 scenarios are at the higher end of the EV uptake forecast by the ESO forecasts.

NPg’s forecast for ASHPs, including hybrids, in their Planning scenario is consistent with the ESO FES Consumer Transformation or Leading The Way scenarios which are at the higher end of ESO forecasts.

The NPg submission of demand profiles in the BPDTs (shown below) shows an increase of around 10% between 2020 and 2028, which is slightly above the equivalent peak demand increase of 8% forecast in the ESO 2021 ‘Leading the Way’ scenario. However, NPg’s suggested increase at the start of ED2 appears inconsistent.

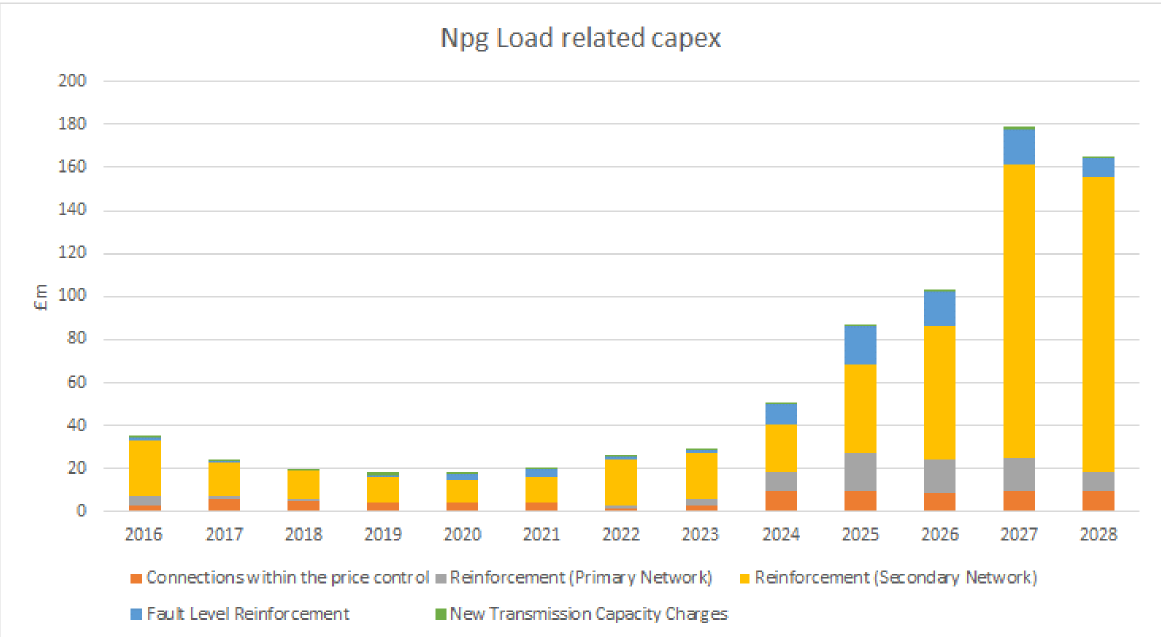


2. Totex - Load related capex

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	643	351%
Connections	46	150%
Primary reinforcement	66	770%
Secondary reinforcement	400	386%
Fault levels	68	854%

NPg's baseline load related capex profile is shown in the above chart and table[3], totalling £643m and an increase of 351% between the ED1 and ED2 period. NPg has provided a breakdown of the proposed unit costs and volumes of investments. However, we would like to see a clearer linkage and justification between the scenarios and the above expenditure categories, demonstrating why the timing of this investment is appropriate.

While the plan proposes that this investment will be needed at some stage in a Net Zero future, we are concerned that this expenditure profile may be accelerating well in advance of demand forecasts and may lead to the wrong reinforcement priorities being chosen.

NPg have also provided a breakdown of the impact of flexibility based solutions on reinforcement expenditure. The following table shows the potential costs and savings associated with this approach.

	£m
Network intervention costs before flexibility-based solutions [a]	841.9
Plus costs of LV monitoring	+20.8
Less savings from price driven flexibility [b]	-113.2
Plus costs of DNO-contracted customer flexibility	+1.8
Less savings from DNO-contracted customer flexibility [c]	-14.1
Plus cost of smart solutions	+9.5
Less savings from smart solutions [d]	-74.1
Expected network intervention costs after flexibility-based solutions [e]	672.7
Gross savings from flexibility-based solutions[(b-c-d)]	**201.3**
Net savings from flexibility-based solutions[(a-e)]	**169.2**

Figure 7: The impact of flexibility-based solutions on network reinforcement costs over the 2023-28 period[10]

While the breakdown is useful, a large proportion of the benefits derive from price driven flexibility, which could be considered a market that would operate outside of DSO involvement. Also, it is not clear how these the non-network benefits e.g., deferred reinforcement, attributed to DSO flexibility have been taken into account in the load related expenditure profile. We would also like to see evidence in the EJPs and CBAs that flexibility has been widely and appropriately considered in the assessment of options.

Also, NPg indicate that they think that distributed flexibility providers are likely to want to participate in national energy and balancing markets rather than DNO network congestion

[3] This table uses the PCFM for the total and the subcategories (and chart data) are taken from the BPDT data to illustrate changes. The BPDT data used does not include ED-2 RPE increases nor ED-1 RPI/CPIH differences. We have not sought to reconcile these relatively small differences at this stage.

flexibility markets. We would welcome further clarification to support the proposed flexibility benefits and impact on load related expenditure assumptions.

3. NLRE totex for ED2

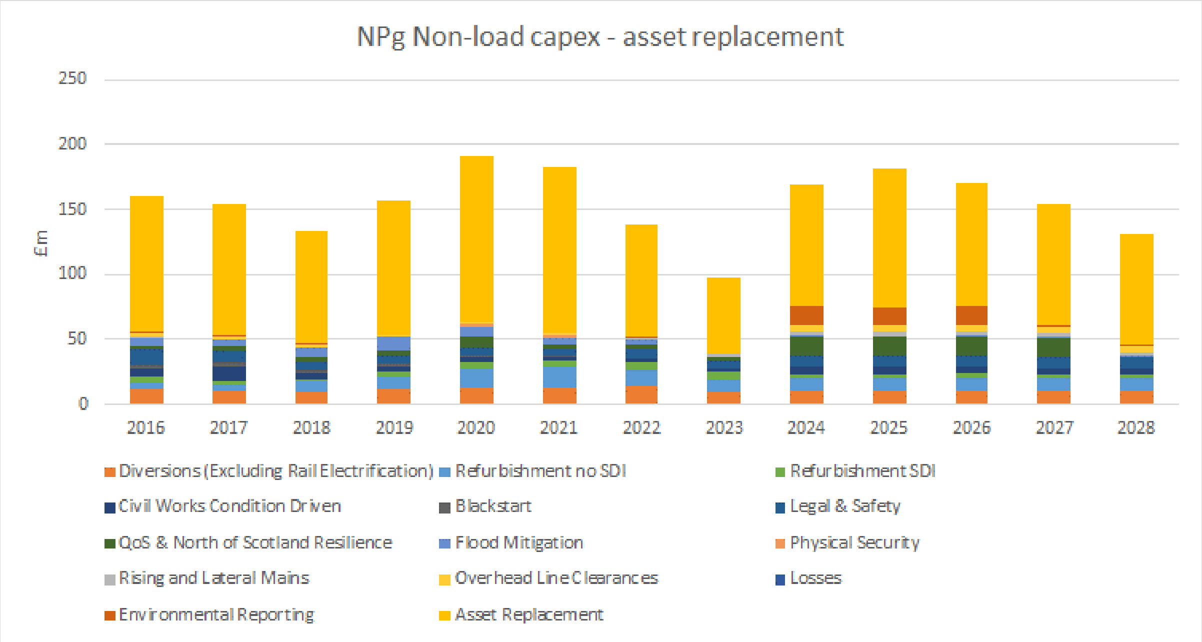
As in the case of LRE totex, we are seeking to understand company investment pathways for non-load related expenditure, and, again, how they have taken account of:

- 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 NPg'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. The charts use BPDT data.

<u>NLRE – asset replacement</u>



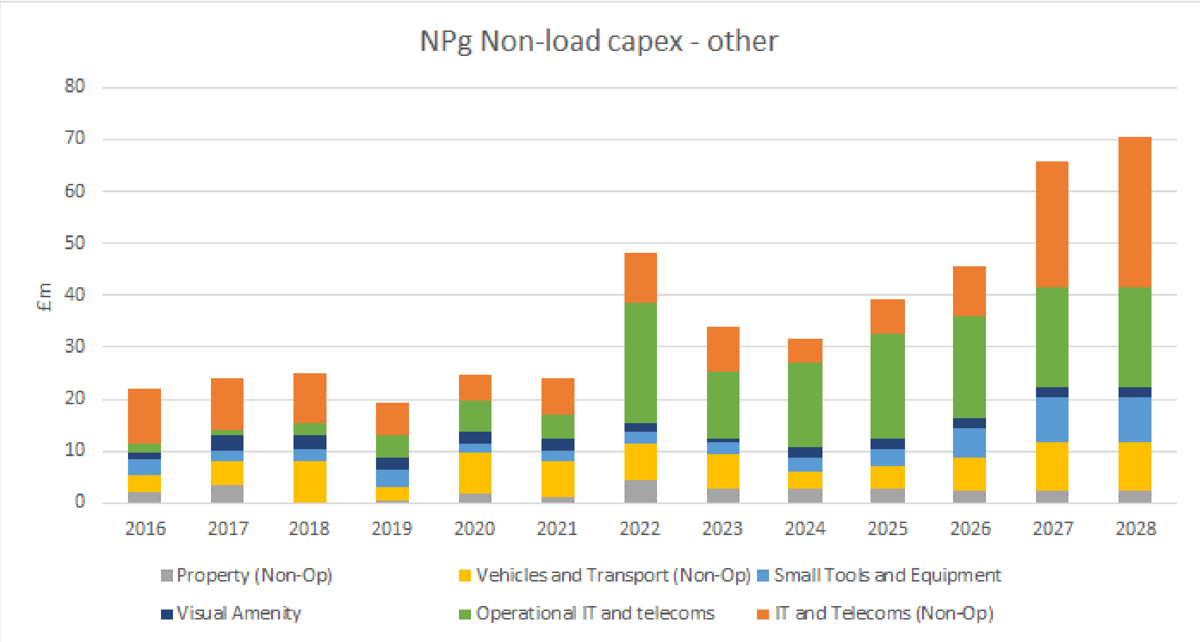
NPg's non-load asset replacement expenditure as shown in the PCFM increases by 12% compared to ED-1. We would welcome clarification of the forecast expenditure and why it has changed from ED1.

As such, we do not think the 12% expenditure increase for ED2 above that for ED1 has been justified. NPg are continuing to maintain largely the same assets as ED1 and we would expect costs to remain stable or potentially reduce as efficiency savings are applied.

We would like to see evidence, in the EJPs and CBAs, of a robust justification for asset replacement expenditure, including consideration that alternatives to SF6-filled switchgear have been duly considered.

<u>NLRE – other</u>

The following chart shows the forecast profile for NLRE – other. There is an average increase of 100% from ED1 driven by significant increases in IT/telecoms.



We welcome additional expenditure where it delivers enhanced network visibility and flexibility markets. We would like to see evidence to demonstrate that this profile can be delivered, together with justifications that show how the benefits from these enhanced outputs are delivered efficiently.

4. Totex - Opex and efficiencies for ED2

NPg's average operating costs increase by 13% overall for ED-2 compared with ED-1, with closely associated indirect costs increasing by 17% and business support costs by 10%.[4]

	ED2 £m	% change
Total Operating costs	1,414	10%
Network operating costs	570	0%
Closely associated Indirect:	445	17%
Business support costs	255	10%

[4] This table uses the PCFM for the total and the subcategories are taken from the BPDT submissions to illustrate changes. We have not sought to reconcile differences at this stage.

NPg justify these increases for DSO establishment and the increased capital delivery programme for load related investment.

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.

Ongoing efficiency - NPg have included a 0.5% pa ongoing efficiency challenge for ED-2. While the NPg 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 NPg's concerns about the disaggregated unit cost modelling and their view that total cost benchmarking is the only approach to benchmarking that fully accounts for trade-offs and synergies across different parts of the cost base. However, we would like to see evidence of independent validation of the unit costs that underpin NPG's business plan.

5. Bespoke uncertainty mechanisms

NPg note that the change to load related expenditure will be the biggest uncertainty in ED-2. Their planned costs are based on the level of investment they forecast will be necessary to meet the number of heat pumps and electric vehicles based on the Governments 10-point plan. They state that, even if uptake is slower than the Government plan, the same assets will still be needed within less than 10 years. This is because many of these assets are ageing and will need to be replaced for asset condition reasons and renewed with larger assets. We don't think this statement has been evidenced.

NPg have proposed uncertainty mechanism for the following circumstances:

- failure of customer price-driven flexibility to materialise at levels assumed in plan. NPg estimate that zero customer flexibility (ToU pricing) will require an additional £186m of LRE
- uncertainty over the number of shared connection cables (looped services) that will require replacement. Based on real world data, NPg have found that services require to be unlooped at 2% of properties where a LCT is installed. 2% x 1071k LCTs = 21400 services at a total cost of £35m (£1635 per service)
- potential faster (or slower) uptake of LCTs than planning scenario. NPg's planning scenario is at the higher end of most scenarios/pathways

NPg indicate that a backstop mechanism could be necessary to avoid the risk of major under- or over-funding, such as the existing 20% reopener for significant variances in load-related expenditure compared to allowances.

Overall, we note that NPg has proposed a high increase in LRE (351%). We think 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.

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.

DSO

NPg set out the following parameters for their DSO outcomes:

- Network visibility - at end ED1, NPg will have 11% of Secondary substations with demand monitoring and are targeting 50% by end of ED2.
- Flexibility markets – 138 MW pa procured over ED2 compared to ED1 forecast of zero MW.
- Costs – NPg's DSO data tables show expenditure of £76m for ED-1 and £87m for ED-2. These are broken down below.

Ref.	Area	Outcome	Data and Digital-isation £m	Network costs £m	Work-force £m	Total £m	FTE
DSO1	Data	Network and market data capture	7.2	20.8	1.2	29.2	3.5
DSO2	Data	Transform our analytical capabilities	18.7	-	2.7	21.4	7.0
DSO3	Data	Enable open energy system data sharing and engage in joint planning	7.9	-	3.7	11.7	9.5
DSO4	Flexibility	Operate and optimise a system with increasing flexibility	12.7	-	5.5	18.1	5.6
DSO5	Flexibility	Facilitate the development of new markets for customers	2.6	-	4.5	7.1	14.0
Total			49.1	20.8	17.5	87.4	39.6[11]

Figure 7: Investment in DSO strategy outcomes over 2023-28 (£ million/full time equivalents (FTEs))

NPg's DSO ambition is for their region to be well on the way to a fully decarbonised energy system by 2028. They are proposing significant investment in the DSO transition over 2023-28 to facilitate potential decarbonisation pathways in a cost efficient manner. They propose a flexibility first approach: ensuring they deploy flexible solutions when it is efficient to do so, instead of conventional reinforcement. Their DSO investment will update systems and skills as well as enhancing data capture, use and sharing to enable optimal use of assets and facilitate the most cost-effective route to decarbonisation.

Overall, NPg has provided a detailed plan and timetable for development of DSO capabilities during ED2. There is a significant increase expected in network visibility from LV monitoring, but flexibility auction assumptions appear low in relation to deferred reinforcement benefits claimed elsewhere. Overall, we find it difficult to ascertain the benefits that are expected to be available as a result of these DSO initiatives, particularly from price based flexibility. A better articulation/quantification of the benefits to consumers would be helpful.

DSO CVP – **Self-service analytics toolkit**

CVP2 NPg plan to build enhanced functionality on top of our open data platform to unlock additional customer benefits. This will include a set of free analytical tools to help with processing data and enhanced self-service. This appears to be a software tool developed by NPg – its not clear whether NPg has the capability to deliver this and whether it is best placed to deliver these benefits.

Digitalisation – some 44% of NPg's digitalisation expenditure of £112m is proposed to be spent on DSO activities. The digitalisation strategy addresses the key areas, but much of it seems to be new initiatives rather so the values ascribed to customer benefits 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.

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
- Collaborate with proactive whole system planning

The whole system outcomes are:

- Removing barriers for customers to use their own equipment to support the power system
- Meet customer needs through cross sector and cross vector planning
- Develop the blueprint for the next generation network by rolling out proven innovation
- Exchange knowledge with those specifying low carbon technologies

Overall, these appear to set out a high level ambition, without being specific about deliverables or benefits. Delivery of proven innovation initiatives will be valuable but we would expect these to become business as usual to deliver whole system benefits, and to be defined in the plan.

CVP's – whole system

NPg propose the following CVP's.

1. Dynamic voltage optimisation for domestic energy efficiency. Aiming to deliver benefits at 27% of properties over the ED2 period, delivering an average annual £20 energy bill reduction.
2. Roll out of next generation energy system – rolling out 30 microgrid solutions in remote parts of the network to enhance resilience.

On the proposition to rollout voltage optimisation technology to around 147 substations serving around 1 million customers over ED2, building on the Boston Spa energy efficiency trials (BEET), at a cost of £8.1m, the claimed energy savings of up to £20 per customer per year are significant and the Challenge Group would welcome clarification in a number of areas, namely:

- The claimed energy savings is up to £20 per customer per annum. What would be a typical saving?
- How are these energy savings actually achieved – through voltage reduction? If so, does this have any impact on the quality of supply delivered to consumers?

- If voltage optimisation is able to impact energy consumption significantly, is this reflected in your demand forecasts?
- What are the anticipated savings in Load Related Expenditure or deferred Asset Replacement resulting from these lower demand forecasts? – there does not appear to be a EJP nor CBA produced for this proposal.
- If the energy savings are delivered through voltage reduction, in the event of a system emergency, has consideration been given to the reduced demand reduction through voltage management available to the ESO ?

With regard to the Microgrid solutions, they may be one option for consumers to improve resilience – other solutions may be the development of their own distributed energy technologies. We would like to understand how proposals for integrated control of distributed energy resources to enhance network resilience are better than the alternatives, and also how the development of such solutions may impact the participation of distributed energy resources in energy and balancing markets.

It is unclear that these CVP proposals offer benefits that customers may want. They may also distort competition in energy and balancing markets through cross-subsidisation.