Panel of Technical Experts

Report on the ESO Electricity Capacity Report 2024

July 2024

Contents

Preliminary Comments & Summary of Recommendations

1. The role of the Panel of Technical Experts (“PTE”) is to scrutinise with impartiality and to contribute to the quality assurance of the annual Electricity Capacity Report (ECR) by the National Grid ESO (ESO). The purpose is to provide technical advice to inform the policy decisions at the Department for Energy Security and Net Zero (DESNZ) for the subsequent Capacity Market auction procurements, through this report and informal consultations.

2. In April and May 2024, the PTE were presented with the initial results from the modelling for the 2024 ECR. In response to comments from PTE and DESNZ the final Report was prepared by ESO and sent to DESNZ on 31 May 2024.

3. The PTE members who prepared this report are Derek Bunn (Chair), Jacopo Torriti, Christopher Harris and Lisa Waters.

4. In fulfilment of our role, we have scrutinised ESO’s 2024 ECR on the target capacity for the proposed T-1 Auction for Delivery Year 2025/26 and the T-4 Auction for the period(s) commencing 2028/29, and this document presents our conclusions.

5. Through the PTE’s previous reports (2014-2023), the PTE has made 81 recommendations in total (of which 8 were from 2023) for improving the methodology and reliability of the modelling by which target capacities are calculated. ESO has taken actions on most of these as reported in the ECR. As usual, we make some recommendations for future work. In doing so the PTE are mindful of the need for the appropriate processes and procedures to be followed ahead of any changes that may be undertaken.

6. The PTE has engaged in relevant discussions with ESO, DESNZ DESNZand Ofgem during the process of ESO formulating the ECR 2024. We are satisfied with the constructive and timely consultations and believe that all parties have worked well together in formulating the analysis and recommendations.

7. The overall analytical approach has been similar to previous years, updated with new information and an evolution in some of the analytics. We have been provided with the modelling documentation and assumptions required for our scrutiny.

8. We discussed thoroughly the sensitivities that went into the modelling and their application in the ‘Least-Worst Regret’ (LWR) criterion to determine the capacities to procure.

9. We have considered the target capacity recommendations by ESO and make the following recommendations:

    - Regarding the T-1 recommendation by ESO of 6.8 GW in the ECR, we have a concern that the proposed procurement target, viewed in comparison to previous years, may be criticised for becoming increasingly risk averse. The proposed 6.8 GW is stated as corresponding to a Base Case Loss of Load Expectation (LOLE) of around 0.1 hours/year and a de-rated margin of 4.3 GW (7.0%) [not taking account of the expected non-delivery]. The comparable values for last year were 0.3 hours LOLE and a margin of 6.3%. Likewise, the risk premium in the proposed target above Base Case expectation this year is 0.6 GW compared to 0.4 GW last year. Last year, the PTE supported the view that it was prudent to remain unusually risk averse; however, in retrospect, as the recent early Winter Outlook 2024/25[1] indicates a margin of over 9%, that procurement may appear to have been over-cautious. If the economic and market outlook is now rather better than last year, it seems hard, therefore, to justify being even more risk averse. An external view might be that the risk premium should not be higher than last year, and perhaps slightly lower. This leads the PTE to suggest that a target around 6.5 GW would be more appropriate. As usual the PTE would suggest an autumn review with respect to new information, particularly on non-delivery.

- Regarding the T-4 recommendation by ESO of 45.0 GW in the ECR, the procurement target looks consistent with the evolving balance of demand and supply and therefore the 45.0 GW target appears credible. However, PTE advocated the new T-5 to T-8 look-ahead analysis last year, mainly on the basis that it may influence deliberations by DESNZ on the T-4 procurement. In the 2024 ECR, the indicative projection for T-5 is for a 49.6 GW requirement, compared to the proposed 45.0 GW for T-4. PTE recognise that this T-5 projection is only indicative and not based upon the same depth of analysis which is undertaken by ESO for T-4. Nevertheless, the indication of a jump of 4.6 GW in one year seems very unusual. Although ESO suggest this could be due to model-based estimates of an increase in peak demand capacity, as well as both CM-eligible and CM non-eligible nameplate capacities, PTE is aware that the new pathway modelling is still work-in-progress and therefore does not advocate using this preliminary indication as a basis to alter the T-4 target.

10. Without having direct evidence to suggest further reductions to these targets, the PTE is concerned about potential over procurement and the consequent costs to consumers. We anticipate that more information will become available in time for any autumn adjustments and suggest that a careful re-evaluation of the supply-side of the Base Case, demand forecasts and the interconnector risks be undertaken at that time.

11. We summarise our recommendations for interconnector de-rating factors below.

[1] Early Winter Outlook 2024/25. https://www.nationalgrideso.com/document/319456/download

PTE Recommended Country De-rating Factors **(**with 2027/28 PTE recommendations included for reference**)**			
	2025/26 (T-1)	**2028/29** (T-4)	**2027/28** (previously)
Ireland Ireland (Greenlink)	 50%	55%	55%
France		68%	65%
Belgium		68%	65%
The Netherlands		68%	62%
Denmark		66%	60%
Norway		82%	91%
Germany		66%	

12. Overall, we were very pleased with the open and constructive process of engagement with ESO and DESNZ. We thank them for their extensive efforts to develop clear and timely analysis and address many of the technical issues which we have raised. We have also taken note of various industry comments, as invited annually by ESO on the interconnector de-rating estimations.

Recommendations

13. The new recommendations in our report are listed below. The numbering follows on from the 81 Recommendations in previous PTE reports.

Recommendation 82: ESO to make use of available smart metered and other relevant data, such as from DNO sources, to improve how the modelling reflects the evolving load shape.

Recommendation 83: ESO should consider distinguishing between implicit flexibility (where demand response is achieved through tariffs) and explicit flexibility (where demand response is achieved through products) when modelling peak demand.

Recommendation 84: ESO should strengthen the analysis in the bottom-up model of peak demand by improving the estimation of sectors' contributions to overall and peak demand.

Recommendation 85: ESO to continue the work on how changes in the drivers of peak demand affect uncertainty analysis around the Base Case.

Recommendation 86: ESO to continue the work started with PTE 61 to characterise more fully the empirical evidence on non-deliveries and non-availabilities.

Recommendation 87: ESO should explore means to update to the Capacity Market Registers to include storage durations, for example by making more use of the post auction reports.

Recommendation 88: ESO to consider the volume and location of storage with non-firm network access and the probability of it being constrained off in certain types of weather events.

Recommendation 89: ESO to provide a more explicit report on whether the potential for congestion across the networks will create material issues, in terms of volume and technologies, for resource adequacy at stress periods.

Recommendation 90: ESO to advance the important work on PTE63 related to de-rating factors for Demand-side Response.

Recommendation 91: ESO to advance the important work on PTE53 related to improved data resources for distributed generation.

Recommendation 92: ESO to continue the analytical and computation work on PTE78 related to the interconnection fleet risk and its implications for the procurement targets.

Recommendation 93: ESO to continue the conceptual work on PTE79 to develop the finer details of how a hybrid LWR and stochastic framework can be implemented.

Introduction

Role of the Panel of Technical Experts

14. The Government commissioned, through an open and transparent procurement process, an independent Panel of Technical Experts (the PTE) for the enduring Electricity Market Reform (EMR) regime, commencing in February 2014. The role of the Panel of Technical Experts ("PTE") is to scrutinise with impartiality and to contribute to the quality assurance of the annual Electricity Capacity Reports by the Delivery Body (now ESO). The purpose is to provide technical advice to inform the policy decisions at DESNZ for the subsequent Capacity Market auction procurements.

15. The PTE's first report on ESO's analysis to inform Capacity Market procurement decisions was published in June 2014. This is the PTE's eleventh report, focused on the modelling and results of ESO's recommended capacity to secure for the 2028/29 T-4 auction and for the 2025/26 T-1 auction.

16. The background of the members and terms of reference of the PTE are published on the Government website.[2]

17. This report has been prepared for DESNZ by Derek Bunn (Chair), Jacopo Torriti, Christopher Harris and Lisa Waters.

Scope

18. The scope of the PTE's work is to impartially scrutinise and quality assure the analysis carried out by ESO for the purposes of informing the policy decisions for the Capacity Market procurement. This includes scrutinising: the choice of models and modelling techniques employed; the inputs to that analysis (including the ones DESNZ provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The PTE reviews whether the analysis is robust and fit for the purpose of Government taking key policy decisions. The PTE assess the limitations of the analysis and how these may impact the Government's deliberations on capacity procurement. This includes, for example, considering potential conflicts of interest ESO or others involved might have in influencing the analysis.

19. The PTE's role is a technical function and it has no remit to make suggestions on the Capacity Market mechanism design, its regulation or wider EMR policy, Government's objectives, or the deliverability of those objectives, unless

[2] https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts

otherwise requested. The PTE's Terms of Reference mean it cannot comment on affordability, value for money or achieving least cost for consumers. These matters are excluded from the PTE's scope and therefore from this report. Nevertheless, the PTE is mindful of the need to avoid the costs to consumers of over-procurement. This means the Panel does not have a role in advising how the analysis should be interpreted for the purpose of those policy decisions, but, where relevant, the PTE has commented on how policies impact the modelling and parameter setting in the ECR.

Process

20. During the course of the PTE's work, ESO has presented its methods, assumptions and outputs in relation to their core task of recommending the auction target capacity in the Capacity Market and the PTE has had opportunity to question ESO during the development of its analysis and recommendations.

21. To carry out its work, the PTE met with ESO, DESNZ and Ofgem regularly during April and May 2024 to discuss development projects, the production plan and modelling outputs for ECR 2024. Subsequently, the PTE provided interim views to DESNZ before presenting preliminary drafts of this report for further considerations and feedback from DESNZ, Ofgem and ESO.

22. The PTE has generally focussed more closely on the areas that appeared to be of highest impact and greatest uncertainty. Accordingly, our commentaries are structured under:

    - Demand forecasts,
    - Supply-side changes, and
    - Interconnector de-rating.

23. As required by the PTE's Terms of Reference, the PTE also kept in mind the potential for ESO to be confronted by potential conflicts of interest. The PTE, throughout this process, has sought to mitigate this by carefully challenging assumptions and, throughout the process, the PTE has maintained a presumption that a natural tendency for any utility or transmission system operator (TSO) would be to be risk averse and to therefore slightly over-secure resources. We note that ESO would bear some of the loss of reputation for any blackouts, and bears none of the costs of over-procurement, and so could be expected to weigh the possible risks of procuring less capacity more than they might credit the cost-savings. The PTE, however, has no evidence that would make us believe that ESO has substantially exploited its privileged position.

24. This report is not comprehensive nor is it a due diligence exercise, but the PTE believes that it has nevertheless identified some important issues that have material consequences. Accordingly, and in line with our approach in previous

years, the PTE has not remarked on details of various matters which were raised and satisfactorily resolved or are part of on-going ESO modelling developments.

25. This report has been prepared from information provided by DESNZ, ESO and Ofgem and the collective judgement and information of its authors. We have also taken account of several written stakeholder responses to the interconnector de-rating material made public by ESO. Whilst this report has been prepared in good faith and with reasonable care, the authors expressly advise that no reliance should be placed on this report for the purpose of any investment decision and accordingly, no representation of warranty, expressed or implied, is or will be made in relation to it by its authors and nor will the authors accept any liability whatsoever for such reliance on any statement made herein. Each person considering an investment must make their own independent assessment having made whatever investigation that person or organisation deems necessary.

Commentary on Analysis and Results

Introduction and context

26. As in its previous ECRs, the ESO lays out its modelling approach and its scenarios and sensitivities that frame its findings on the amount of capacity to secure in the auctions to meet the Government's 3 hours Loss of Load Expectation (LOLE). Whilst the 3 hours LOLE has been the expressed target, in practice it has been interpreted as 3 hours LOLE under a cautious ("Least Worst Regret", LWR) consideration over a range of sensitivities and scenario conditions. This means that the unconditional LOLE in recent years, under the assumption that the Base Case expectations are unbiased, has been much less than 3 hours. Given the difficulty of communicating the LOLE target, we find it very useful to see in the ECR that the recommendations indicate how the anticipated de-rated margins and risk premiums (i.e. target minus Base Case procurements) compared to previous years. The major elements in the analysis are GB Demand and Supply, together with an increasing reliance upon Interconnection resources from neighbouring countries. The de-rating factors are crucial, and we assess whether the overall methodology is fit-for-purpose. We therefore organise this section according to these main elements.

GB Demand

General Comments

27. Peak electricity demand is the starting point for the ECR, and ESO has evolved the methodological principles from previous years. The new reliance on pathways rather than scenarios influences peak demand modelling. The 2024 FES[3] framework, which prioritises strategic routes to net zero, reduces the emphasis on exploring a wide range of outcomes and is less predictive but more normative in its focus.

28. The previous PTE Recommendation 66[4] consisted of accelerating the work on the statistical representation of peak demand uncertainty around the Base Case for the T-1 and T-4 years, with a clear identification of which uncertainties can be modelled statistically and which are being left to expert judgement. While the modelling includes the load shapes from 2005/06 up to 2021/22 in measured historical demand profiles, ESO has also investigated, as part of their EMR111 development project, whether a statistical model of demand trained on the most recent 3-5 years of demand behaviour can be used. This approach reflects the most recent demand behaviour as well as potentially allowing tweaks to the

[3] 2024 FES framework. https://www.nationalgrideso.com/document/322316/download
[4] PTE report 2022. https://assets.publishing.service.gov.uk/media/62d57678e90e071e7f6f71ba/panel-technical-experts-2022-report.pdf

demand profile in future ECRs, based on expected load profile changes (e.g. Electric Vehicles (EVs) smart charging behaviour) in the target years.

29. The use of the apparently outdated (up to 2021/22) measured historical demand profiles may potentially affect the accuracy of the evolving load shapes. The PTE welcomes the statistical model of demand being trained on the most recent 3-5 years of demand behaviour. There are many smart metering data opportunities to be harnessed. For example, a Distribution System Operator (DSO) incentive 2023/24 submission reported taking the initiative to ask DESNZ for access to disaggregated consumer datasets and were granted access to 162,535 datasets for a year. ESO should take similar initiatives on smart metering data.

Recommendation 82: ESO to make use of available smart metered and other relevant data, such as from DNO sources, to improve how their modelling reflects the evolving load shape.

30. An important methodological step in domestic peak analysis in the ECR involves determining a percentage reduction in peak demand based on a sample of smart meter roll-out data and applying this percentage reduction to the overall peak demand. We note however that the ECR methodology for domestic peak response does not include any distinction between implicit (i.e. half-hourly metering variable pricing rates such as Time of Use tariffs and Critical Peak Pricing, such as Triad) and explicit (i.e. direct Demand-Side Response (DSR) intervention programmes like the Demand Flexibility Service, DFS) demand flexibility. Ofgem’s retail market review data used in the ECR does not yet include the percentage of customers on Time of Use tariffs, i.e. domestic peak response through implicit flexibility.

31. It is preferable to distinguish between implicit flexibility (where DSR is achieved through response to tariffs) and explicit flexibility (where DSR is achieved through products) when quantifying the amount of capacity to secure in order to avoid the risk of double counting. Previous examples of quantification of implicit flexibility consist of Ofgem Impact Assessment of the Market-wide Half-Hourly Settlement, where the estimated level of load shifting away from the system peak (i.e. implicit flexibility) was calculated as the product of the proportion of customers with a smart tariff and the percent of demand shifted at peak by customers with a smart tariff.

Recommendation 83: ESO should consider distinguishing between implicit flexibility (where demand response is achieved through tariffs) and explicit flexibility (where demand response is achieved through products) when modelling peak demand.

32. In the ECR methodology, after establishing the underlying annual demand, a recent historical relationship between annual and peak demand is applied. This forms a baseline peak demand, to which unpredictable peak demand components are added, such as EV charging or heat pump usage during peak times on the transmission system.

33. We note that the historical relationship between annual and peak demand components is based on outdated data. Similarly, the contribution of residential electricity demand to the bottom-up demand model relies on old data. However,

research shows this contribution has changed after COVID-19 due to increased working from home.[5] Additionally, there is currently no provision to model the industrial & commercial sector's contribution to peak demand in the bottom-up model.

Recommendation 84: ESO should strengthen the analysis in the bottom-up model of peak demand by improving the estimation of sectors' contributions to overall and peak demand.

Uncertainty Analysis

34. The current ESO methodology evaluates uncertainty by integrating sector-specific uncertainties into its Monte Carlo model for losses and metered demand. This approach allows for the estimation of probability distributions for peak demands in the heat, transport, and industrial & commercial sectors. These distributions are then used in the Monte Carlo model to calculate uncertainties in both sector-specific and total demand, as well as their correlations. We are surprised that the consequent uncertainty bounds appear to be constant around the Base Case over the T-1 to T-4 horizon, as conventional forecasting theory would indicate wider confidence intervals with longer lead times.

35. The PTE observe that prior to the recent two years, the high demand sensitivity above Base Case was regularly about half its current levels and we question whether a higher recent risk aversion is becoming sustained out of context.

36. Previous Recommendations PTE52[6] and PTE59[7] emphasised the importance of re-visiting the factors affecting peak demand and potential stress period behaviour given the importance of the drivers on the shape of peak demand and its impact on the capacities to secure. The high peak demand sensitivity at T-1 needs stronger justification as it is materially influential in the procurement.

37. The PTE note that there are not yet in place measures to systematically investigate the drivers, such as Low Carbon Technologies (LCT) and Distributed Energy Resources (DER), as well as shape of peak demand (e.g. the time of the day when peak demand occurs). The uncertainty analysis should be consistent with empirical evidence related to forecast accuracy. For instance, uncertainty around the penetration of EVs and heat pumps is currently based on FES assumptions and not updated LCT data. Embedded Capacity Registers and LCT registers represent opportunities for up-to-date inputs to the modelling.

38. Uncertainty analysis will depend on modelling of peak demand and the extent to which changes are captured by data and forecasts. For example, LCT will feature changes in overall demand and introduce sharper peaks in demand. In addition,

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[5] A research paper (https://www.sciencedirect.com/science/article/pii/S0378778823006588) shows that residential electricity consumption increased by 7.8% in year 1 of the pandemic and by 2.2% after the pandemic compared with the pre-pandemic consumption levels.
[6] PTE report 2020. https://assets.publishing.service.gov.uk/media/5f0c85f5d3bf7f039d024477/panel-technical-experts-report-on-2020-electricity-capacity-report.pdf
[7] PTE report 2021. https://assets.publishing.service.gov.uk/media/60e371138fa8f50abf416f65/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf

the outcomes of uncertainty analysis will differ depending on when peaks in demand take place (e.g. seasonality of heating and cooling, EV effects, etc.).

Recommendation 85: ESO to continue the work on how changes in the drivers of peak demand affect uncertainty analysis around the Base Case.

GB Supply

General Comments

39. The supply projections in the ECR, as in previous years, remain comprehensive and plausible. The non-delivery risk remains substantial for both Capacity Market and non-Capacity Market plants. While ESO models non-delivery based on historic figures, the PTE has been concerned that non-delivery could increase as a result of the recent reported increase in late delivery of connections by the transmission and distribution companies. There is also a risk that the inflationary impact on project costs may make previously secured agreements undeliverable, for both Capacity Market and non-Capacity Market plants, illustrated by the cancellation of some projects and the Contracts for Difference Allocation Round 5 (CfD AR5) results. We therefore agree it is right to include some additional assumed non-delivery in the Counterfactual (CF) case, consistent with previous ECRs where some additional assumed non-delivery was included in the most pessimistic case.

40. Non-delivery is easier to see than over-delivery and for T-1 the known (+0.4 GW) and unknown (+3.1 GW), looks relatively robust. However, looking further out to the T-4 will always be more challenging, as we note the concerns over supply chains and connection dates across the market. In terms of non-delivery of embedded plant, the PTE comment that the figures look quite high. Market intelligence indicates some concern that the asset registers, maintained by the Distribution Network Operators (DNOs), may not be entirely reliable, thus making it difficult to identify which type of technology has higher non-delivery within the embedded assets. The PTE hopes that Ofgem will be able to persuade the DNOs to improve their asset registers to dependably record what is connected to the DNO networks and how (e.g. co-located assets).

41. It remains the view of the PTE, as set out in previous Recommendation PTE61[8], that some empirical analysis of all past non-deliveries (and non-availabilities), as well as evident market responses, should be undertaken to look for any possible drivers of dependence between technologies, relevant Capacity Market auction clearing prices and average energy market prices. While there is some market commentary on larger plants, the understanding of embedded generators remains a significant weakness in the ECR modelling. For example, we understand that battery prices have come down significantly, but all other technologies have seen cost increases.

[8] PTE Report 2021. https://assets.publishing.service.gov.uk/media/60e371138fa8f50abf416f65/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf

Recommendation 86: ESO to continue the work started with PTE 61 to characterise more fully the empirical evidence on non-deliveries and non-availabilities.

42. The PTE does not address policy matters but given the critical effects of non-delivery risk in the ECR modelling, the PTE notes that further policy considerations could be helpful in reducing non-delivery risks. For example, it would be possible to make changes to the Capacity Market Rules so that visibility of non-delivery of Capacity Market plant would be earlier in the year. This would allow ESO to reflect on non-delivery changes earlier in the modelling process. In this regard, it was noted in PTE recommendation PTE62[9] that better timing of all Capacity Market related activities each year would allow pre-qualification and auction results to inform the ECR and give parties longer to deliver new build plant after the T-4 auction. Furthermore, if parties could trade Capacity Market agreements before reaching their Substantial Completion Milestone (SCM) that may also reduce non-deliveries.

43. Last year the PTE noted the end of Renewables Obligation (RO) support for some of the biomass generation plant in 2027, which impacts about 2.5 GW. It is still unclear what will happen to this technology, though we note it opted out of the Capacity Market pre-qualification last year. The consultation on a "Transitional support mechanism for large-scale biomass electricity generators"[10], which may give a different support to the largest biomass plants, indicates that even if not in the Capacity Market the plant may remain operational under a different regime. The ESO's assumption that the total nameplate capacity of RO supported dispatchable capacity becomes eligible for the Capacity Market seems sensible therefore given this lack of certainty, as the plant can enter the T-1 auction if it has not secured a different funding regime.

44. As the remaining RO plant sees its subsidies end, there remains the option for them to join the Capacity Market. The PTE considers that this will depend on their view of the business risks and the de-rating factors offered. Keeping older plant open may be uneconomic. In light of the network connection queues, it may be more economic for these plants to redevelop their sites. This is another reason that ESO needs far better data on embedded plants, and the changes that may be seen, in terms of both redevelopment and co-location.

45. The storage de-rating factors have changed, because of more shorter duration capacity being installed. This results in the distribution of stress events at 3 hours LOLE shifting towards longer events as more of the shorter events can be avoided by using the short-duration storage capacity. However, it is not clear that the storage assets would dispatch in a sequential manner that would minimise expected unserved energy (EEU). Without an actual Capacity Market stress event to base assumptions on, the PTE considers that the storage operators will make dispatch decisions based on their individual views of the duration of the stress event combined with market prices and Capacity Market penalties. Notwithstanding the fact that no stress events have yet occurred to test storage

[9] PTE Report 2021. https://assets.publishing.service.gov.uk/media/60e371138fa8f50abf416f65/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf

[10] https://www.gov.uk/government/consultations/transitional-support-mechanism-for-large-scale-biomass-electricity-generators

behaviour, in line with previous recommendation PTE71,[11] storage de-rating could begin to be informed by operational data now that more storage is on the system and active in the Balancing Mechanism.

46. The PTE is aware that the Capacity Market Rules can enable storage, unlike other technologies, to declare their own connection capacity from which they are derated. We are therefore concerned the potential contribution of storage to security may be being understated, as the Capacity Market declared capacity could be a lot lower than the installed capacity at storage sites. Market intelligence suggests storage assets may have been declaring at lower capacities and with longer duration. In practice, storage can discharge at different rates depending on the circumstances it is responding to. A possibility is that the Capacity Market's Extended Performance Test (EPT) requirements are incentivising these declarations. The lack of details on storage in the Capacity Market registers makes it difficult to check if this is a material issue but, given the increase in storage, the PTE considers this is worthy of further investigation. PTE notes that in the post auction results the storage durations are reported, and therefore observe that it should be possible for ESO, through advocating a rule change, or otherwise, to facilitate updating the Capacity Market Registers to include storage durations.

Recommendation 87: ESO should explore means to update to the Capacity Market Registers to include storage durations, for example by making more use of the post auction reports.

47. The PTE agrees with the assumption that no new nuclear will be due to come online until towards the end of the decade, in line with EDF's statements around the expected completion of Hinkley Point C.

48. The PTE believes that there is more downside risk facing the delivery of new offshore and onshore wind capacity and the CF looks more realistic than other pathways. There are many recognised risks facing developers including the late delivery of transmission connections, supply chain delays and planning delays. However, once operational the PTE is concerned that their contribution to security may be under stated by the Equivalent Firm Capacity (EFC) methodology. Using operational data to check or inform the EFC methodology needs to be considered, in line with recommendation PTE70.[12] The PTE recognise there is a degree of correlated wind output at all wind speeds, and the average contribution of incremental wind capacity to stress periods therefore decreases, but still feel the underlying operational data is relatively old and the new locations of wind farms may influence observed operations today.

49. As in previous years, the actual data on the embedded capacity remains a concern. ESO assumes some over delivery, with plant staying open without a Capacity Market agreement. What would drive this behaviour is unclear, however, especially as this would now be gas plant which seems most likely to

[11] PTE report 2022. https://assets.publishing.service.gov.uk/media/62d57678e90e071e7f6f71ba/panel-technical-experts-2022-report.pdf
[12] PTE report 2022. https://assets.publishing.service.gov.uk/media/62d57678e90e071e7f6f71ba/panel-technical-experts-2022-report.pdf

be in the Capacity Market. With tightening emissions standards,[13] increasing costs, concerns over running hours, and other detrimental factors, the Capacity Market income is crucial so that without it many of those plants may close. What seems more probable is that non-delivery will increase for the same reasons that are impacting wind of transmission connected plant developers; increased prices, supply chain risks and late delivery of connections.

Targets for T-5 and T-8

50. The PTE thanks ESO for responding to their recommendation (PTE80[14]) to include an indicative look-ahead to possible T-5 to T-8 target capacities. This indicative view will be useful to the market and policy makers not only in considering how the Capacity Market may develop, but in also considering the transitional issues, with some plants likely to come off for conversion to new fuels, or close earlier if policies to tighten emissions were adopted, etc.

51. The need to consider how the net zero transition can be accommodated within the Capacity Market structure is important. While a policy, not methodology issue, the PTE would note that the Capacity Market-eligible capacity requirement in future years seems optimistic around the transition to hydrogen in particular, as set out in the FES 2024 Hydrogen Evolution pathway. Policy developments to date[15] have aimed to promote the development of hydrogen and CCUS, thereby helping to support new businesses. However, considering the economics, transportation issues, etc. it is not clear to us that hydrogen use will, at least initially, be widespread in power stations in addition to local industrial hubs. It seems more probable hydrogen will want to locate near customers such as chemicals producers. Further, if hydrogen is new build, as ESO considers it could be, then in addition to the usual new project development risks, it may be in a long connection queue and not able to join the market before the mid-2030s.

52. Given no decision on Sizewell C has been made, delivering new nuclear capacity in the 2030s also looks optimistic. Small Modular Reactors (SMRs) may be delivered faster, but at the current time we are not aware of any designs nearing clearance for use within GB. The previous government's nuclear technology competition[16] suggested delivery by mid-2030s.

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[13] Emissions rules tightened for delivery from 2024, meaning some obligated plant in 2023/24 can no longer enter the Capacity Market. https://assets.publishing.service.gov.uk/media/62fd0581e90e0703e6100b92/capacity-market-emissions-guidance-2022.pdf

[14] PTE report 2023. https://assets.publishing.service.gov.uk/media/64b5d6100ea2cb001315e436/panel-of-technical-experts-2023-report.pdf

[15] https://www.gov.uk/government/publications/uk-hydrogen-strategy

[16] https://www.gov.uk/government/news/six-companies-through-to-next-stage-of-nuclear-technology-competition

Wider Supply Side Issues

53. Looking further out there are a number of developing issues that the PTE also considers worthy of attention. The first is the non-firm transmission connections being offered to storage and the increasing number of connections subject to Active Network Management (ANM) requirements by network companies. While the modelling generally assumes that in a stress event all Capacity Market plant can access the system, this may not happen in some stress events. If we recall the "beast from the east"[17], where it was windy, but gas plants were struggling due to extreme cold, similar circumstances could lead to a lot of storage north of the B7[18] boundary being constrained off. The increasing constraints across the transmission system and within the distribution networks means it may not be the case that Capacity Market obligated plant can always run. While all connections are 'non-firm' to a degree, there is a lack of industry understanding as to how interruptible these new connections will be.

Recommendation 88: ESO to consider the volume and location of storage with non-firm network access and the probability of it being constrained off in certain types of weather events.

54. With the current review of connections ongoing, as well as access arrangements being considered under REMA[19], in the longer term it may be necessary to consider how much capacity, and of which technology types, does not have firm system access rights. How policy makers choose to develop the market rules may have a material impact on the way the ECR modelling develops over time.

55. The PTE has previously suggested (PTE51[20]) that ESO needs to develop a methodology for dealing with co-located facilities. Given the connections queue it would appear more assets are likely to consider co-location and if only one asset could run in a stress event this should be considered in the modelling. It would seem likely it is mainly solar co-locating, and therefore the impact in a stress event is likely to minimal, but this needs to be substantiated.

56. The congestion across the networks is now also a material issue for significant periods of the year. While it used to be the Scottish generators who were mostly constrained off, the transfer capacities across southern boundaries, such as B15, LE1 and EC5, can also now see extended periods with active constraints. The PTE feels it would be remiss to go on ignoring the potential impact of constraints on the ability of the networks to deliver energy from all available power stations or interconnectors in a stress event.

Recommendation 89: ESO to provide a more explicit report on whether the potential for congestion across the networks could create material issues, in terms of volume and technologies, for resource adequacy at stress periods.

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[17] 22 February - 5 March 2018.
[18] https://www.nationalgrideso.com/research-and-publications/electricity-ten-year-statement-etys/electricity-transmission-network
[19] Review of Electricity Market Arrangements
[20] PTE report 2019. https://assets.publishing.service.gov.uk/media/5d25f04eed915d691a890098/Panel_of_Technical_Experts_report_2019.pdf

57. The PTE is also concerned that the previous government consulted on further tightened emissions limits[21] which may result in some conventional plant running out of operating hours within a year. While a prudent operator may save running hours for periods where they feel a stress event is most likely, there will be a commercial trade-off between paying non-delivery charges in a stress event, with the capped liability, and making profits in other periods of high prices. We are not sure that this could be an explicitly modelled. The PTE would like to note that if future changes are made to emissions limits in the CM, if this cannot be appropriately modelled by the ESO, there may be options the government could explore that could help to mitigate the risks of assets operating in a way that could be detrimental to electricity security, such as moving the start of the emissions year to October.

58. Some of the issues arising in the Capacity Market will play out over the next few years, as we see hydrogen develop, plant come out of the RO, etc. The PTE would note that this may not necessarily alter the target capacity to secure but may warrant DESNZ revisiting the historic set aside for the T-1. For example, if a number of gas plants come out of the Capacity Market to convert to hydrogen, it may be prudent to encourage them come back into the next available T-1 auction by having a larger target.

De-rating factors

59. The calculation of the de-rating factors remains the same as previous years, so there is no methodological change for the PTE to comment on. The PTE notes and welcomes ESO's recent consultation[22] on changing the methodology for calculating the storage de-rating factors. However, we understand that while the scaled EFC element can be implemented immediately (subject to the outcome of the consultation), the technical availability of batteries and consideration of storage charging between stress events are policy issues, requiring government approval as to when any changes may be made, and no change may be implemented this year.

60. The majority of the de-rating factors are only showing small changes from last year. Most conventional generation technologies continue to have de-rating factors in the high 80%'s to mid-90%'s, while nuclear remains in the upper 70% (see ECR figure 9A). The de-rating methodology uses the average availability, based on the maximum export limit (MEL) during the winter peak period (07:00-19:00, Monday-Friday, December-February) at times with demand above the 50th percentile (all plant except CCGT, CHP and autogeneration) or 90th percentile (CCGT and autogeneration) over the last seven years. As noted previously this may over or under play the availability of plant not in the BM and therefore not declaring MELs.

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[21] https://www.gov.uk/government/consultations/capacity-market-2023-phase-2-proposals-and-10-year-review

[22] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/ESO-Storage-De-rating-Factors-Consultation-2024-V1.pdf

61. On autogeneration, the PTE noted that this plant has historically been used by industrial customers to manage Triad demand reduction. With the removal of the Triad this plant may become less reliable and/or leave the market. ESO agreed this could be an effect and to consider this further.

62. The PTE is aware that there will be an energy transition issue that government will need to consider regarding the de-rating factors when plant is coming off for low/no carbon conversion, e.g. biomass becoming carbon capture, gas turbines hydrogen converting, etc. The de-rating factors may also be influenced by whether the plant remains in the Capacity Market or becomes subject to different obligations under a different support scheme. ESO already distinguishes between Capacity Market obligated plant and non-obligated plant, and it could also have to define de-rating factors for untested technologies or for plant subject to obligations to run in stress events as part of the scheme they are under. These issues may require Capacity Market Rule changes and therefore will need consideration relatively soon.

63. At the moment DSR de-rating is estimated based on a three-year rolling average of the availability of non-BM STOR (Short Term Operating Reserve), as defined in the Capacity Market Rules. Estimating DSR de-rating using the mean committed STOR availability of Non-BM STOR providers over the last three winters during winter peak period potentially disregards more recent developments in DSR market. For instance, the volatility of STOR price affects participation, with parties unwilling to take on obligations with high risks of low rewards. There are also issues around exclusivity clauses, especially when new services have been made available for DSR in recent winters (e.g. DFS), which have the effect of ruling the sites out of other services. In future, the move to a new Balancing Reserve[23] product may also provide more relevant data.

64. It remains unclear if DSR is real demand reduction or if it is on-site generation used at times of system stress to create a "DSR effect". If it is the latter, then the de-ratings at c79% may underplay the contribution to security these sites make. If it represents real DSR then a better understanding of why its de-rating is lower may be useful. The PTE also questioned whether DSR should be duration limited as it seems unlikely that DSR made up demand reduction can be sustained for days if required. We note ESO's methodology is set out in the Capacity Market Rules and therefore not open to change without a rule change and the government may therefore want to consider the wider policy around the treatment of DSR.

65. It is still worth noting that the DSR de-rating factor increase this year due to the move of non-BM STOR to day-ahead procurement from seasonal contracts, but the PTE are not convinced that much non-BM STOR is actually DSR, rather than generation. ESO could potentially use the DFS service data to see how well DSR can respond when called. This comes back to the issue of needing better information on embedded assets as a whole. The PTE feels it may be beneficial for ESO to see if improvements in this area could be made, possibly as part of the 10-year Capacity Market review (see recommendation 82).

[23] https://www.nationalgrideso.com/industry-information/balancing-services/reserve-services/balancing-reserve

66. For the variable renewable generation technologies, wind and solar photovoltaic (PV), ESO uses two distinct approaches. For the auction target capacity, the wind EFC is calculated by the Dynamic Dispatch Model (DDM) for the entire fleet. The recommended auction de-rating factors, in contrast, are based on incremental EFCs for wind as calculated using the Unserved Energy Model (UEM). These incremental EFCs represent the contribution to security of supply brought by delivering any additional wind units via the Capacity Market.

67. As previously, wind has a higher EFC than solar PV (due to PV not being available in the evening peak). The wind de-rating factors have decreased slightly, while solar PV has increased, now at 5.4% for T-1, and 6.5% for T-4. ESO noted last year that de-rating factors for solar have increased as increased short-duration storage capacity shifts the distribution of stress events towards longer events that start earlier in the day (when there is some solar output).

68. Both offshore and onshore wind see reduced de-rating factors as their capacity expands. Under the EFC methodology, the additional capacity has a decreasing impact of the EFC, hence the de-ratings come down in the EFC calculations.

69. As noted by the PTE in previous years, while still supporting the forward-looking, model-based approach to derive de-rating factors from EFCs, we believe there is sufficient data to back-test these models and perhaps integrate a more statistical approach into the modelling. As noted above, there may also be changes in the original modelling assumptions as locations of both PV and wind are more diverse and the technologies themselves have moved on, for example the size and height of wind turbines.

Interconnections

General Comments

70. Interconnectors present specific challenges with respect to their (de-rated) contribution to the capacity target. These are primarily:
    i) The Interconnector Operator (ICO) is an entity distinct from the Transmission System Operator on either side (even if owned by them) and all other entities and subject to specific rules and commitments;
    ii) The ICO remuneration structures differ on each side of each interconnector and between interconnectors;
    iii) Whilst there can be some incentive to increase congestion rent by restricting flow (generally precluded by the agreements), this is in practice not a major factor, and interconnector flow is predominantly determined by the relevant market rules (e.g. coupling and capacity), with the System Operators (SOs) on either side having a degree of control to manage factors such as constraints and security;
    iv) Even within the EU, the evolution of market coupling makes interconnector flow complex from the perspective of Capacity and Congestion

Management. In GB we have two further specific cross jurisdictional complications with Norway (whose EU relationship is as a member of the European Economic Area), and the island of Ireland governed by the Trade and Cooperation Agreement and the Single Electricity Market;

v) Unlike generation, storage and DSR, there is no energy that is directly controlled by the ICO and any energy contract is with the SO's which themselves have no primary ownership control of energy input and output;

vi) There is no universally agreed economic model of interconnection and this presents challenges for example with loop flow (transit driven by physics as well as markets), and flow against the direction of market prices

vii) The general principle of SO to SO countertrade in circumstances of curtailment, but the very limited evidence of resolution of curtailment by countertrading;

viii) The role of storage as complement to interconnection for diurnal flow variation; and

ix) A collection of behavioural complications by all actors, such as nation states and SOs.

71. It follows from all these challenges that any interconnector modelling must make major simplifications and that any model-based results must be interpreted as representing idealised, frictionless risk assessment. As previously, the PTE is in broad agreement with the modelling taken by the ESO. Nevertheless, the serious consequences of sustained pan European energy stress and the specific effects of treaties/agreements, rules/regulations and practices on electricity flow through interconnectors go beyond the model-based results. Going forward, it may be useful for ESO to consider explicit conditions under which interconnector flows may diverge from the ideal.

Interconnector De-rating Factors

72. The PTE is required to suggest values from within the ranges provided in the ECR. Whilst a substantial amount of thought has been undertaken by ESO on looking at the fleet risk and what it means for correlated flow reductions at times of stress, we consider this to be work in progress that needs further refinements before we feel confident in endorsing a substantial change to the de-rating factor assessments. Our approach has therefore been a pragmatic one of considering the market evidence for changing the de-rating factor values from last year. We summarise our recommendations for interconnector de-rating factors below.

PTE Recommended Country De-rating Factors (with 2027/28 PTE recommendations included for reference)			
	2025/26 (T-1)	**2028/29** (T-4)	**2027/28** (previously)
Ireland Ireland (Greenlink)	 50%	55%	55%
France		68%	65%
Belgium		68%	65%
The Netherlands		68%	62%
Denmark		66%	60%
Norway		82%	91%
Germany		66%	

73. **Ireland**. We note an increasing commonality of wind and solar resources and (critically) opposite time lags, with wind generally arriving in Ireland some hours before GB and sun arriving in GB about half an hour before Ireland. All other things being equal this would create diurnal reversals of interconnector flows. However, ESO has noted the current tightness in Ireland. Overall, whilst there are reasons to be optimistic about more efficient flows in the future, and in the short term it is hard to justify any change in the de-rating factors. The de-rating factor is the same as the PTE recommendation in 2021 for the T-4 auction for the 2025/26 Delivery Year.

74. **France.** The situation in France continues to evolve, and the ESO's recent outlook is more encouraging than a year ago. Accordingly, we recommend an increase in DRF to 68%. Over time it may be that the planned Celtic link to Ireland reduces flow to GB if/when total export capability is limited, but this may be counterbalanced by continuous work on improving their nuclear fleet fault issues.

75. **Belgium.** We concur with ESO's analysis. As with the previous year, it seems sensible, given the market coupling, geographical proximities and interconnections, to give the same rating as France.

76. **Netherlands.** The Netherlands is likewise well connected within Northwest Europe and we again do not have evidence to differentiate it from Belgium.

77. **Denmark.** Danish flows are closely connected with those of its neighbours. Transit from Norway to and through Denmark is to some extent in competition with export from Norway to GB. There are internal constraints currently limiting the full use of the Viking Link, except when German power is spilling into Denmark. The de-rating was low last year in advance of operations starting up. We recommend an increase to 66% to reflect an established period of operation.

78. **Norway**. The energy balance in Norway is tightening whilst the importance of Norwegian export flows is increasing. Most significantly, Norway has cited potential interconnector curtailment in relation to water resources, network issues and energy security. We therefore recommend reduction in the DRF from Norway for this reason. We recommend a new DRF of 82%.

79. **Germany.** The expectation of the situation with interconnection to Germany will be in flux over the next few years. On one hand there is a new and long interconnector. On the other hand, global experience in long interconnectors is growing rapidly. With regard to bulk energy flow, Germany is highly interconnected and has diurnal and seasonal flow variation with developing constraints on the north-south axis. The resource situation in Germany is in flux, as described by ESO. Overall, putting all these factors together, we recommend a DRF of 66%, which is the same as Denmark.

80. The PTE has engaged constructively with ESO. We would welcome greater insights into the characterisation of the causes of potential stress events, with examples below in this paragraph. We recognised that the model has to be artificially stressed to replicate failure events, since there have been no historical stress events to facilitate empirical analysis. Nevertheless, more intuition would be useful regarding the likelihood and types of stress events. These could include for example sustained hydro shortage in Norway, delay in nuclear fleet resolution in France, generator type faults, reduced gas inflow to Europe, stored gas depletion, dunkelflaute by depth and duration and scale, pan European cooling water challenges, high demand peak in GB, sustained pan European heat/cold, or widespread interconnector curtailments. The sample of data should also reveal any trends over time.

81. The very large amount of interconnector build has been in recognition of the value of interconnector flows, in bulk transfer of energy, seasonal transfer, and more regular two-way reversal especially on the East-West axis. In turn, with the interconnectors being built, they are increasingly relied on. Whilst flow through Alternating Current (AC) interconnectors is subject to some control, much greater control is possible with Direct Current (DC) interconnectors. The result of this is that the relative weight of contracts/agreements vs physics tends to increase when modelling DC interconnector flows.

82. We recognise that ESO has based their analysis upon the Baringa estimates, but we consider that a broader synthesis of sources might be beneficial. We are aware of data which show, for example, that the rates of generating asset replacements across Europe and the margin trends are declining.

83. Taking all this into consideration and bearing in mind prior engagement between ESO and PTE, and with no major differences, our focus has been on what has changed and what is changing. The main changes have been in Norway and France, and the knock-on effects of these. The main change going forward is a general tightening of energy balance as Europe struggles to replace the flexibility that has been provided by fossil power generation. This in turn increases the likelihood of pan European stress from sustained high residual demand (demand minus Variable Renewable Energy) and thence increasing attention to what interconnector curtailment would actually happen in such an event. Hence the importance of considering the limitations of a model-based approach and the implications of treaties, agreements and behavioural frictions. Whilst we have recommended small changes according to country specifics, we may expect significant country by country changes in future, driven more by considerations of treaties and agreements than an idealised physical flow across a homogenous continent.

Methodology

84. The PTE has always made a number of recommendations in its previous reports. Last year's (2023) PTE report made eight new Recommendations. All these recommendations, along with others raised by DESNZ, Ofgem and ESO's internal post review/update processes were considered by ESO. Below we summarise our comments upon how these eight Recommendations have been developed.

PTE #	PTE 2023 Recommendations	Progress and PTE Comments
74	To review and clarify how the extreme FES scenarios can be quality assessed as predictors of ranges for the short-term forecasts and how, or if, they should be used alongside the estimated probability distributions around the Base Case.	Whilst the switch from scenarios to pathways has been a major feature, that does not affect the more focussed requirements of the ECR to provide shorter-term forecasts and uncertainties. We consider that the uncertainty analysis around the Base Case remains work-in-progress.
75	To monitor the change, if any, in demand responses to peak periods as a result of the Triad disappearance.	We note that this was not assigned high priority last year and not taken forward by ESO. Nevertheless the PTE suggests that this be re-considered this year.
76	To consider how over-delivery can be brought into the general stochastic methodology alongside the progress already achieved with non-delivery and demand.	This remains to be completed as part of the overall move to a fully stochastic model.
77	To consider the use of operational data for estimating wind de-rating factors with explicit reference to the weather-induced correlations between demand and supply and the calibration of wind power functions.	We accept the re-considered view of ESO regarding to need to maintain updated wind-power functions for the technology mix in the fleet of wind turbine. The correlation issue remains part of a wider development of the historical data.
78	To explore further the risk arising from correlated weather patterns across Europe. In particular, to continue the statistical analysis of Interconnector de-rating factors to understand the implication of weather correlations on the aggregate risk of GB interconnections at times of stress and to consider potential new risk measures that go beyond simple averages in order to better represent the risks from bimodal and correlated flows.	This is a large project in which ESO have already done substantial analysis. Nevertheless, there is more work to be done on the statistical weather patterns as well as the risk analysis of bimodal and correlated interconnector flows at times of stress.
79	To present a vision of the procurement decision analysis framework as the methodology evolves away from LWR to a fully stochastic risk simulation.	A start has been made on this but there is more conceptual and modelling work to be undertaken.

PTE #	PTE 2023 Recommendations	Progress and PTE Comments
80	To provide some methodological suggestions on a more future-contingent approach to T-4 procurement in order to take account of the prospect of emerging disruptions in the energy transition.	A good start on including a T-5 to T-8 look ahead was made within this ECR. However, the precision of forecasting appears to need further development over this horizon.
81	To consider whether T-1 and T-4 remain the optimal target years for resource adequacy procurements.	This remains mainly a policy question for DESNZ.

85. With regard to Recommendations going back further than last year, we note the substantial progress on PTE71 related to storage de-rating factors with various proposals sent out for consultation by ESO. Responses to this are expected be published concurrently with ECR 2024. In addition, we note further developments on PTE63 related to de-rating factors for DSR and PTE53 on improved data for embedded resources, notwithstanding an on-going need for further achievements on both of these projects. Of increasing importance is also the on-going analysis of ancillary services (PTE68) with respect to how reserves would be used to meet demand in stress situations.

86. As many of the previous recommendations are still work-in-progress, the PTE would like to re-affirm the importance and priorities that should be given to some of these, particularly PTE63 related to de-rating factors for DSR and PTE53 on improved data for embedded resources, as mentioned in this report in the Domestic Supply section. We recognise that these initiatives may also require Government and Regulatory commitments.

Recommendation 90: ESO to advance the important work on PTE63 related to de-rating factors for DSR.

Recommendation 91: ESO to advance the important work on PTE53 related to improved data resources for distributed generation.

87. Regarding PTE 74 on demand uncertainty, we continue to question whether the demand modelling is sufficiently precise for ECR purposes in the short term. The FES move to pathways has a much longer-term focus on policy, whilst the ECR procurement analysis requires precision in the uncertainty estimates around the Base Case at T-1, T-4 and over the look-ahead range T-5 to T-8. In the ECR, the PTE's opinion is that the peak demand uncertainty at T-1 is excessive, that the confidence intervals of T-1 to T-4 should not logically be constant but increasing over lead time according to standard forecasting theory and that a large jump of 4.6 GW in the indicative procurement from T-4 to T-5 reflects an artefact of the baseline projections. We are aware that there are substantial challenges in the stochastic modelling of demand and appreciate that the current state of the

forecasting methodology is still work-in-progress. A recommendation to continue to advance PTE74 was articulated in the Demand section of this report.

88. Regarding PTE78 on the aggregate fleet risk from interconnectors, the new insights from this more explicit modelling of correlated flows is insightful and creates a serious concern about the impact to GB of pan-European stress. PTE considers that more analysis is required. The GB stress events necessarily have to be artificially created in the modelling but, nevertheless, as noted in the Interconnection section previously, it would be important to understand more about the likelihoods and characteristics of these stress events. This would give a view on the degree of risk involved. We suggest that more conceptual analysis may be required to develop an alternative, forward-looking and more appropriate set of stress events from which to base the average de-rating factors appropriate to meeting the reliability standard.

89. Also related to the fleet risk, the ECR only gives a brief verbal description of how the pan-European modelling gets summarised into EFCs, which in turn get re-calibrated into a functional relationship of GB net inflow on GB margin in the DDM model. It would be useful to have a more explicit description of this process and reassurance that the bimodality and correlations identified in the pan-European modelling do carry through into the DDM determinations of procurement risks. Overall, the PTE considers it incorrect to seek to adjust the mean de-rating factors, based upon recalibrating the average flows from each country over the more extreme cases, as presented in the ECR. PTE suggests that it would be more aligned to portfolio risk theory to take the distributional features into the tail risk assessment for the overall fleet contribution to the procurement target. An increased tail risk for the fleet will lead to a lower EFC for the interconnection fleet, which should carry through into the procurement calculation. More precisely, this raises the question of whether a re-specification of the modelling linkage between the interconnector and DDM models needs to be undertaken. Furthermore, if there is a strategic concern about the quantum of interconnector supply in the Capacity Market procurement due to its bimodal risk, that could be addressed through other measures, such as by policy, or, perhaps, by apportioning the fleet EFC. In summary, we consider that more analytical development of the fleet risk and its implications for procurement needs to be continued.

Recommendation 92: ESO to continue the analytical and computation work on PTE78 related to the interconnection fleet risk and its implications for the procurement targets.

90. Regarding PTE79 related to the vision of a hybrid LWR and stochastic risk analysis, the PTE is concerned that in the transition towards a more distinctive methodology, there are some modelling risks of double-counting risk and circularity in uncertainty assessments. The essence of the vision is that elements

that can be estimated statistically (demand, outages, weather) should be expressed as distributions, whilst special event risks (e.g. major non-deliveries, Base Case alternatives) should remain in the LWR. The expectation is that the number of LWR alternatives will be fewer and that the overall analysis, as a consequence, becomes less discretionary. There are increased challenges in moving into this modelling framework and it may require a more computationally intensive modelling capability to both integrate the DDM, UEM and pan-European models currently in use and to facilitate more complex simulations. Many of the elements are not independent, but at this intermediate stage of development, they are treated as independent. This introduces error into ESO's combined risk implications.

91. Likewise, greater clarity is needed on what should be included in the statistical distributions and what should be treated separately as distinct unusual events. Furthermore, whilst the LWR has been useful in providing a comfortable risk premium above the Base Case procurement, the risk premium may have to be addressed explicitly as the role of the LWR calculation is diminished and more of the uncertainties may be combined into one density function. In the extreme, with one combined density function and no LWR, there would be one procurement outcome at LOLE of 3 hours and, as a consequence, a "comfortable" risk premium would need to be added ex post. Other modelling visions of a hybrid LWR and stochastic framework are possible. Accordingly, the PTE encourages ESO to press forward with this work at both the conceptual and computational levels.

Recommendation 93: ESO to continue the conceptual work on PTE79 to develop the finer details of how a hybrid LWR and stochastic framework can be implemented.

Conclusions on Target Capacities

92. Overall, we note the continued improvement in methodology for producing the ECR and whilst we have, as usual, presented a number of recommendations, we hold the opinion that the work is comprehensive and thoroughly undertaken.

93. On T-1, we have a concern that the proposed procurement target, viewed in comparison to previous years, may be criticised for becoming increasingly risk averse. The proposed 6.8 GW is stated as corresponding to a Base Case Loss of Load Expectation (LOLE) of around 0.1 hours/year and a de-rated margin of 4.3 GW (7.0%) [not taking account of the expected non-delivery]. The comparable values for last year were 0.3 hours LOLE and a margin of 6.3%. Likewise, the risk premium in the proposed target above Base Case expectation this year is 0.6 GW compared to 0.4 GW last year. Last year, in the PTE report, we argued that it was prudent to remain unusually risk averse; however, in retrospect, as the recent Winter Outlook 2024/25: Early View[24] indicates a margin of over 9%, that procurement may appear to have been over-cautious. If the economic and market outlooks are now rather better than last year, it seems hard, therefore, to justify being even more risk averse. An external view might be that the risk premium should not be higher than last year, and perhaps slightly lower. The PTE suggests that a target around 6.5 GW would therefore be more defensible.

94. On the T-4 recommendation by ESO of 45.0 GW in the ECR, the procurement target looks consistent with the evolving balance of demand and supply and therefore the 45 GW target appears credible. However, PTE advocated the new T-5 to T-8 look-ahead analysis last year, mainly on the basis that it may influence deliberations by DESNZ on the T-4 procurement. In the 2024 ECR, the indicative projection for T-5 is for a 49.6 GW requirement, compared to the proposed 45 GW for T-4. PTE recognise that this T-5 projection is only indicative and not based upon the same depth of analysis which is undertaken by ESO for T-4. Nevertheless, the indication of a jump of 4.6 GW in one year seems very unusual. Although ESO suggest this could be due to model-based estimates of an increase in peak demand capacity, as well as both CM-eligible and CM non-eligible nameplate capacities, PTE is aware that the new pathway modelling is still work-in-progress and therefore does not advocate using this preliminary indication as a basis to alter the T-4 target.

95. As usual we would suggest an autumn review of parameters with respect to new information, particularly on non-delivery.

[24] Early Winter Outlook 2024/25. https://www.nationalgrideso.com/document/319456/download

Quality Assurance

96. Previously followed procedures continue to provide QA and these are closely aligned with DESNZ internal QA processes. The PTE previously requested details of the ECR Quality Assurance methodology and this was reproduced in Annex 2 of PTE’s 2016 report.