Panel of Technical Experts

Report on the National Grid ESO Electricity Capacity Report 2021

July 2021

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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 Reports by National Grid ESO. The purpose is to provide technical advice to inform the policy decisions at BEIS for the subsequent Capacity Market auction procurements, through this report and informal consultations.

2. The annual scrutiny cycle for this PTE report started in August 2020 with consideration of several special projects being undertaken by National Grid ESO related to their modelling. These deliberations continued through the autumn. By April and May 2021, the PTE were presented with the initial results from the modelling for the 2021 ECR.

3. The PTE members who prepared this report are Professor Derek Bunn (Chair), Dr Guy Doyle, Professor Nick Jenkins, Professor Frank Kelly and Lisa Waters.

4. In fulfilment of our role, we have scrutinised National Grid ESO's 2021 Electricity Capacity Report on the target capacity for the proposed T-1 Auction for delivery year 2022/23 and the T-4 Auction for the year commencing 2025/26, and this document presents our conclusions.

5. Through our previous reports (2014-2020), the PTE has made 57 recommendations in total (of which 6 were from 2020) for improving the methodology and reliability of the modelling by which target capacities are calculated. National Grid ESO has taken actions on most of these as reported in section 2.5 of the ECR. As usual, we make 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 National Grid ESO, BEIS and Ofgem during the process of National Grid ESO formulating the Electricity Capacity Report 2021. 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. We have been provided with the modelling documentation and assumptions required for our scrutiny.

8. We agreed on the sensitivities that went into the estimation and the application in the 'Least-Worst Regret' criterion to determine capacities to procure.

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

- For T-1, we accept the recommendation of 4.5GW in the ECR but register concern that it will be a high procurement which may test the depth of the market liquidity. Anticipation of this need to procure may attract more facilities to pre-qualify. Nevertheless, we recommend a detailed reconsideration of the supply-side of the base case and the non-delivery sensitivities in the autumn.
- For T-4, we accept the 44.1 GW recommendation in the ECR but also register concern that this value reflects a high component of risk aversion due to delivery uncertainties. Again, we recommend a detailed reconsideration of the supply-side of the base case and the non-delivery sensitivities in the autumn. A substantial set-aside may also be prudent.

10. Without having direct evidence to suggest reductions to these targets, the PTE is concerned about potential over procurement and the consequent costs to society. 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 and the non-delivery assumptions be undertaken at that time. Related to this, we have been informed that the Ofgem review of market responses during winter 2020/21 will then be available, as well as relevant new data through the pre-qualification process and any possible Capacity Market Agreement terminations. The move away from using the Root Sum of Squares (RSS) approach, as previously, to a simple summation of multiple plant risks has increased the quantitative impact of the non-delivery sensitivities. We recommend further clarification on the rationality of this before any autumn adjustments. We also note that the peak demand adjustments made this year are influential and we have recommended a future development project to take a closer look at the drivers and way uncertainty is modelled in the forecasting process.

11. We summarise our recommendations for interconnector de-rating factors below. They are mostly based, as previously, upon pan European modelling of potential power flows at times of stress under the scenario that assumes countries will be moving towards their stated reliability targets based upon the methodology developed by ENTSO-E in accordance with the Clean Energy Package.

PTE Recommended Country De-Rating Factors for 2025/26 with previous 2024/25 for reference		
	2025/26	**2024/25**
Ireland	50%	50%
France	76%	76%
Belgium	66%	69%
The Netherlands	68%	63%
Denmark	69%	57%
Norway	91%	99%
Germany	61%	n/a

12. Overall, we were very pleased with the open and constructive process of engagement with National Grid ESO and BEIS. 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 invited by National Grid ESO on the approach to interconnector derating estimation.

Recommendations

13. The new recommendations in our report are listed below. The numbering follows on from the 57 Recommendations in previous PTE reports.

Recommendation 58: A more comprehensive feed-forward analysis of how all of the main drivers of demand will evolve from the existing situation to influence the T-1 and T-4 base case peak demands should be developed to enhance the insights from the FES scenarios. This should provide a more comprehensive and a more explicit representation of the ranges of uncertainty around the base case forecasts with these ranges of uncertainties being quantified as much as possible.

Recommendation 59: The previous Recommendation 52 regarding the factors affecting the evolution of peak demand and potential stress period behaviour should be re-visited soon given the importance of the drivers on the shape of peak demand and its impact on the capacities to secure, particularly the T-4 value.

Recommendation 60: The Root Sum of Squares or Simple Summation approach to multiple non-delivery risks needs to be fundamentally reconsidered in terms of the independence of the risks involved, or their dependence on common mode drivers, and their possible market responses induced. We suggest a more flexible rationale be developed based upon the characteristics of the different non-delivery risks.

Recommendation 61: An 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 CM auction clearing prices and average energy market prices.

Recommendation 62: BEIS and Ofgem should consider the timing of all CM related activities each year in order to allow pre-qualification and auction results to better inform National Grid ESO's modelling and give parties longer to deliver new build plant after the T-4 auction.

Recommendation 63: A more thorough analysis of the duration limits for turn-down DSR should be undertaken.

Recommendation 64: The consistency of the implicit derating of interconnectors for the DDM procurement analysis and the determination of individual country derating factors should be made more transparent.

Recommendation 65: Further analysis of the availability of DSR and Embedded Resources in Europe at the times of GB stress should be undertaken.

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 National Grid ESO, in its role as Delivery Body for the Capacity Market. The purpose is to provide technical advice to inform the policy decisions at BEIS for the subsequent Capacity Market auction procurements.

15. The PTE's first report on National Grid's analysis to inform Capacity Market decisions was published in June 2014. This is the PTE's eighth report, focused on the modelling and results of National Grid ESO's recommended capacity to secure for the 2025/26 T-4 auction and for the 2022/23 T-1 auction.

16. The background of the members and terms of reference of the PTE are published on the Government website.[1]

17. This report has been prepared for BEIS by Professor Derek Bunn (Chair), Dr Guy Doyle, Professor Nick Jenkins, Professor Frank Kelly and Lisa Waters.

Scope

18. The scope of the PTE's work is to impartially scrutinise and quality assure the analysis carried out by National Grid 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 BEIS provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The PTE review whether the analysis is robust and fit for the purpose of Government taking key policy decisions. This includes, for example, considering potential conflicts of interest National Grid ESO or others involved might have in influencing the analysis.

19. The PTE has no remit to comment on the Capacity Market mechanism design, its regulation or wider EMR policy, Government's objectives, or the deliverability of those objectives, unless 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-

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

procurement. The role of the Panel is a technical function and not a forum for policy commentary or for advising the Government on its objectives, the policies being implemented or policy decisions surrounding them. 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 have commented where these impact the modelling and parameter setting in the ECR.

Process

20. During the course of the PTE's work, National Grid 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 National Grid ESO during the development of its analysis and recommendations.

21. To carry out its work, the PTE met with National Grid ESO, BEIS and Ofgem regularly during the autumn/winter 2020/21 to discuss development projects, the production plan and modelling outputs for 2021. Subsequently, the PTE provided interim views to BEIS before presenting preliminary drafts of this report for further considerations and feedback from BEIS, Ofgem and National Grid ESO.

22. The PTE has generally focussed more closely on the areas that appeared to be of highest impact and greatest uncertainty. Key areas that emerged included:

    - Demand evolution
    - Non-delivery estimation and aggregation
    - Interconnector de-rating

23. As required by the PTE's Terms of Reference, the PTE also kept in mind the potential for National Grid 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 TSO would be to slightly over-secure resources. We note that National Grid 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 weight 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 National Grid ESO has substantially exploited its privileged position and hence there has been no conflict of interest concern up to the time of writing this report.

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 development.

25. This report has been prepared from information provided by BEIS, National Grid 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 derating material made public by National Grid 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, National Grid 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). The major elements are domestic Demand and Generation, together with an increasing reliance upon Interconnection resources from neighbouring countries. The de-rating factors are also crucial, and we need to assess whether the overall methodology is fit-for-purpose. We therefore organise this section according to these main elements.

Demand

27. Forecasting peak demand is the natural starting point for the ECR, and the methodology undertaken by National Grid ESO followed the same principles as in previous years. The details however are steadily being refined and improved. The Underlying Demand is made up of metered National Demand (75%), Distributed Generation (23%) and Demand Side Response (1.2%). Forecasting peak demand is challenging as only 75% of demand is metered at the level of the transmission grid and this fraction is decreasing, as embedded generation increases. National Demand has reduced by more than 11GW in the 10 years to 2019/20. Demand forecasting has become increasingly difficult with changes in consumer engagement and embedded energy resources. We have discussed at length the steps taken by National Grid ESO to remain vigilant to these changes and have actively supported efforts to improve data on distributed resources.

28. The impact of COVID-19 has created particular difficulties in the forecasting of underlying peak demand this year. A number of changes were made in the forecasts of expected peak demand over the summer of 2020 and early 2021. A reduction of 3% in the peak demand due to COVID-19 was used in the initial calculations for the auction for capacity for winter 2021/22. It was subsequently concluded that there should be no reductions due to COVID-19 in peak demand forecasts for subsequent years. It appeared that COVID-19 created an anomalous set of circumstances, and that the methodology used to determine the underlying peak demand was not appropriate during the changes brought about by COVID-19.

29. The peak demand forecast for future years in the ECR uses an estimate of the winter peak of the current year (known as the outturn Average Cold Spell peak demand). Due to the impact of COVID-19, the established methodology for this calculation was not able to estimate reliably the winter peak demand of 2020/21. Thus, the winter peak demand of 2019/20 was used as a starting point for estimating the winter peak

demand for 2021/22 and subsequent years and so there is this a two-year gap in data and some increased uncertainty in the load forecasts.

30. We are concerned about the uncertainty around the demand forecasts and in this respect the FES scenarios are not the most appropriate basis for representing the ranges of short-term uncertainty around the base case. In the ECR, the dispersion of the FES scenarios is not designed to be a range of uncertainty around the base case, but rather indicates a few selected alternative trajectories to the base case. Thus, the dispersion of the FES scenarios in ECR 2021 became narrower in the medium term than in the short term, before widening again over the longer term. Uncertainty ranges around the base case would, in contrast, be logically expected to get steadily wider.

31. We therefore recommend that a new short-term uncertainty modelling approach should be developed to enhance the insights from the FES, as an adaptive feed-forward analysis around the base case, rather than a backward induction from long term scenarios. A feed forward analysis would start from the existing situation and consider how all of the main drivers of demand will influence the T-1 and T-4 base case peak demands and the uncertainties around these effects. This should provide a more comprehensive and a more explicit representation of the ranges of uncertainty around the base case forecasts than is indicated by the dispersion of the FES scenarios. The ideal would be to move the methodology towards developing 95% confidence intervals around the T-1 and T-4 base case forecasts and we suggest National Grid ESO give some thought to if, and how, the uncertainties can be quantified with this ideal in mind.

Recommendation 58: A more comprehensive feed-forward analysis of how all of the main drivers of demand will evolve from the existing situation to influence the T-1 and T-4 base case peak demands should be developed to enhance the insights from the FES scenarios. This should provide a more comprehensive and a more explicit representation of the ranges of uncertainty around the base case forecasts with these ranges of uncertainties being quantified as much as possible.

32. Recommendation PTE44 of 2019 was intended to provide a more explicit analysis of the potential load shape evolutions and their implications for peak demand. This recommendation was not taken forward in 2019/20. Recommendation PTE52 of 2020 was a revised and expanded version of Recommendation PTE44 and suggested that ‘The factors affecting the evolution of peak behaviour should be analysed more explicitly from the broad perspectives of current and future technical, society and regulatory evolutions’. Of particular concern is that the peak may be getting broader and flatter, with implications for duration limited resources. Moreover, the impact of COVID-19 has increased further the importance of Recommendation PTE52. It was encouraging to note that some progress has been made on addressing Recommendation PTE52 but work has yet to commence on some important elements of the work plan. We note that in the past 12 months the Government has published an Energy White paper and set a target to move the UK to net zero carbon emissions by 2050. Many of the policy aims will involve significant electrification of the economy,

some of which such as a move to electric heating and more electric vehicles are highly likely to impact peak demand, especially if consumers do not respond to the signals that it is hoped policies like half hourly settlement and smart meters are designed to deliver. Given some of the forecasts around the take up of EVs, etc. considering the evolution of peak demand shape and the timings of stress periods are increasingly important.

Recommendation 59: The previous Recommendation 52 regarding the factors affecting the evolution of peak demand and potential stress period behaviour should be re-visited soon given the importance of the drivers on the shape of peak demand and its impact on the capacities to secure, particularly the T-4 value.

Domestic Supply

33. National Grid ESO's modelling results for the T-1 auction is significantly driven by non-delivery of both plants with Capacity Agreements for 2022/23 that either will not or are unlikely to deliver, as well as slightly lower levels of renewable generation and autogeneration. Looking out to 2024/25, there will remain a non-delivery risk due to older plant shutting, as we have now seen with Dungeness B, as well as potentially lower non-capacity market plant delivery.

34. Last year the PTE noted that National Grid ESO analysis suggested that the market generally appears to close plant due to fundamental plant economics rather than from discernible decreases in reliability. In the past year the market has seen the closure of large gas plants (going into administration, though two are now out of administration but declared unavailable for winter 21/22) and a lack of availability from nuclear plant, which is not necessarily unexpected from aging plant.[2] We note this observation has been made in several other markets in the EU and elsewhere. Combined with the potential impact of COVID-19 on the ability to deliver new plant on time, either conventional plant or renewables, the outlook for supply this year has been more challenging for National Grid ESO to model.

35. The PTE notes that the level of non-delivery reported by National Grid ESO over the winter 2020/21 has been far higher than in previous years and the impacted plant in the Capacity Market have not all traded out of their Capacity Market Agreements. How much of this plant will come back for the delivery year 2022/23 or beyond is difficult to tell, but the PTE believe that National Grid ESO's modelling has sensibly reflected the observations from the market. They have given due consideration to risks to thermal plant, and the impacts of embedded benefits being removed from smaller plant. The range of scenarios run around station availabilities, DSR and interconnectors, in our

[2] The PTE note that EDF Energy has announced it is to permanently closes Dungeness B nuclear plant, which has Capacity Market Agreements of c1.1GW for the delivery years to October 2024.

view, remain robust. We do not consider that National Grid ESO's modelling has a "recency bias" and has not over-reacted to observed behaviour in winter 2020/21.

36. However, the PTE is concerned that the distinction between non-delivery and non-availability may not have been described in way that is clear to all readers. Section 3.10.4 of the ECR describes what National Grid ESO observed in 2020/21 and when it observed it. Non-delivery that becomes apparent soon enough can influence the target in the T-1 auction, the final opportunity for the Secretary of State to request National Grid ESO to secure capacity for the winter. The relevant distinction may therefore be when non-delivery becomes apparent to National Grid ESO. The PTE notes that there will be benefits in more clarity on the differences between non-delivery and unavailability, with the former being, for example, plant secured in the Capacity Market auctions that is then not built or renewable plant that is retired. All power stations have periods where they are not available, but whether this influences their derating factors depends upon whether and when they were submitting MELs. For the readers of the ECR, clarification on these terms and their contexts would be useful.

37. The PTE note that National Grid ESO estimated that observed non-delivery during the coldest part of last winter (early December 2020 to early February 2021) exceeded 5 GW. While this could be made up in the T-1 auctions, evidence from the auctions held earlier this year suggests that buying larger volumes at short notice increases the auction clearing price, though this was the first year that the T-1 clearing price had been higher than the relevant T-4 price. The PTE understands that Ofgem is looking into whether there was embedded capacity, including DSR, which did not respond to the market signals on high priced days over the last winter.

38. Unfortunately, Ofgem's work on plant operations last winter has not been completed and the PTE has not been able to take into account any findings by Ofgem. The PTE notes that the reduction in embedded benefits for distribution connected power stations will have increased the price at which they will want to run, but it may be useful for BEIS to know more about what drove behaviour last winter before finalising the target capacity for the T-1 auction. If the capacity was available, but chose not to run for economic reasons, then rising prices should mean secure supplies are maintained, albeit at higher prices. We understand from Ofgem that this information will be available in time for any autumn adjustments to the target capacity.

39. The PTE remains concerned that the data National Grid ESO relies on for forecasting embedded plant remains less robust than that which it has for transmission connected assets, though we welcome the Embedded Capacity Register. PTE Recommendation 53 noted that better data on embedded plants should be sought and we are disappointed National Grid ESO has not found a way to secure this data, for example raising a code rule change (to the BSC, DCUSA or CUSC)[3] to require publication of real time data on at least the larger embedded plants. We note that BEIS proposed, but is not currently progressing, making all Capacity Market Units (CMUs) into

[3] BSC – Balancing and Settlement Code, DCUSA – Distribution Connection and Use of System Agreement and CUSC – Connection and Use of System Code

Balancing Mechanism Units (BMUs). This would allow the same data to be collected on small plants as are published on all larger plants. While adding all plants into the Balancing Mechanism may be difficult in the short term, requiring the publication of MELs and actual output data into a central register (publicly visible) would provide more robust data. Until this data starts to be collected, the market will not understand the full scale of over/under delivery from this section of the market and the de-rating factors applied to embedded assets will not be as accurate as desirable.

40. The PTE has also previously noted that the reduction in “embedded benefits”, that started in 2018 and was phased over three years, may impact the delivery of embedded generators. While we agree with National Grid ESO it is a sector wide impact, it will have altered the economics of older plants in particular. The changes in the ancillary services market may also have impacted some of these plants and over time environmental legislation is expected to reduce their operations. While we agree with National Grid ESO that plants taking part in the more recent auctions will have known about some of those changes, we remain concerned that non-delivery from this sector may increase unless changes to market rules are made to make replanting and/or trading out of agreements easier.

41. The PTE notes that non-delivery is also difficult for parties themselves to signal under the capacity market rules. The reasons for terminating a Capacity Market Agreement are relatively tightly defined and there is no option for parties to simply tell the Delivery Body that a plant will be terminated at a point in the future.

42. For example, if a plant was being decommissioned due a major fault discovered in October, the probability is it will fail to provide Satisfactory Performance Days (SPDs) and as a result will be terminated in July the following year; some 9 months after the owner may have known it was shutting. The PTE suggests that BEIS may want to give consideration to allowing parties to terminate agreements, albeit with an associated termination fee. The PTE note that Ofgem has been planning to review the rules around trading Capacity Market Agreements, which may allow some agreements to be traded rather than terminated, and we believe this could materially reduce non-delivery.

43. Since last year, the Government has consulted upon moving the date for all unabated coal plant to close to 2024. With limited operational years remaining it would be unlikely any remaining coal plants would be repaired in the event of a plant failure. The PTE notes that no coal plant entered the T-4 auction for delivery in 2024/25. Plant remaining on the system may also have limited running hours due to environmental legislation and capacity payments alone are unlikely to be enough to keep these sites open. However, tighter margins for the coming winters may see these plants enter the T-1 before they shut by October 2024.

44. The economics of gas plant is driven by the price of gas and carbon, both of which remain uncertain 4 years out. The PTE agrees with National Grid ESO that there appears to be limited scope for over delivery, albeit there are a number of gas plants that opted out or did not take agreements in the T-4 auction for 2024/25 and could

therefore come into the T-1 auctions at a later date, along with those that have been terminated due to administration. As with coal, for 2022-24 there is a risk from aging plant and some will be impacted by environmental legislation, but analysis by National Grid ESO last year in response to PTE Recommendation 45 looked at whether aging impacted reliability and found it did not, as reported in the ECR 2020.

45. The PTE agrees with National Grid ESO that the CCGTs are the plant most likely to respond to market conditions, and there remain a number of plants with no agreements from the T-4 auctions for delivery in 2024/25, c3.7GW, which may come into the Capacity Market for a one-year agreement later. The plants that Calon Energy owned had all their capacity agreements terminated which does reduce the secured capacity for 2022/23 by 2GW and it remains unclear if some of this plant will choose to participate in the auction for delivery in 2022/23, or later years.

46. With the start of the UK's own carbon emissions trading scheme, National Grid ESO has forecast carbon prices similar to those seen in the EU emissions trading market. It is reasonable to expected alignment of the UK ETS with the EU ETS. However, the PTE notes that any upward divergence in the price of allowances and other carbon costs could make UK generation more expensive than overseas plants and may affect availability or delivery. The PTE suggests that BEIS keeps this under consideration as the full repercussions of Brexit on energy policy become clearer.

47. Over time non-delivery by DSR seems to have fallen, though it is not clear why this is happening. National Grid ESO report that the observed Triad avoidance in winter 2019/20 was 2.4GW, but last winter this fell to 1.3GW. The PTE believes non-delivery may have reduced in situations where the DSR market has matured or some capacity agreements held by DSR have been traded on to third parties, for example to generators. While the FES scenarios see the role of DSR increasing, it is not obvious that market participation is likely to be focussed on the Capacity Market as the obligations are significant (with no limit of the response time required in a Capacity Market Event). Instead, the PTE would expect to see more active customer involvement in other areas of the market.

48. Last year the PTE recommended that National Grid ESO examine the reliability of HVDC links in the light of cable issues seen with interconnectors, on IFA, Moyle and EWIC in 2016/17, Britned 2020/21, and within the GB transmission network on the Western link. We also note the late commissioning of the Eleclink interconnector expected in 2021/22. We note that National Grid ESO support this proposal, but that they have reported that the technical performance of interconnectors is within BEIS remit and not theirs. We therefore encourage BEIS to progress this examination.

49. Setting aside physical performance, non-delivery of interconnectors is also driven by the capacity available in the markets which connect to GB. Like the UK, other countries, notably France and Belgium, have aging nuclear plant that may result in non-delivery due to longer or more frequent than expected outages. The PTE is satisfied that National Grid ESO has recognised both of these non-delivery risks in its modelling.

50. However, we note that in combining all of the sources of non-delivery, National Grid ESO have reversed the previous approach of using the Root Sum of Squares (RSS) and now simply sum the risks. The PTE considers that this could increase the risk of overestimating non delivery from the sum of the various sources if they occur independently. We suggest this approach be re-considered carefully in the light of whether there are independent sources of risk and, as a consequence, endogenous market responses when substantial non deliveries occur.

51. We suggest that it might be useful to conceptualise the issue in terms of the extent to which the risks are (a) independent, in the sense that the occurrence of one does not change the likelihood of the other, or (b) subject to a common mode effect (e.g., market circumstances) implying dependence, and (c) have the potential to induce counterbalancing market response effects. To the extent that the delivery risks correspond to (a) will lead to RSS as the appropriate “portfolio risk” measure for independence, or to (b) for a simple summation of dependent risks. In either case (c) may be applicable. There may also be other appropriate approaches. We recognise that such a categorisation would change over time and that such a conceptualisation would represent a more flexible approach.

52. PTE31 looked closely at how non-delivery risks should be aggregated. Coal and gas non-delivery were recommended to be combined into a single figure for thermal non-delivery since the key drivers for potential non-delivery were the same (profitability in the energy market). The key drivers in other technologies were different (from thermal and from each other) and were kept separate. The project concluded that while not perfect, the RSS approach gave the more robust answer (ECR2018). Market response was calculated subsequently to this calculation. As a consequence, the RSS approach grouped together technologies affected by the same drivers for non-delivery, but treated non-delivery over different groups of technologies as independent. This year’s ECR, informed by the non-delivery observed in 2020/21, has instead added together potential non-delivery across different groups of technologies. It is possible that the key drivers have changed since 2018, and one possibility may be that the various incentives and disincentives created by the Capacity Market itself have contributed to this change. For example, if there is little disincentive for non-delivery in a particular year then that may be a driver shared across all technologies. There may be an issue of weakness in the “satisfactory performance day” rules, for example, allowing a plant to be declared unavailable for the whole winter without the Capacity Market Agreement being terminated. Another common driver could be several plants coming to the end of their lives at the same time and facing similar maintenance issues.

53. Related to this aggregate effect of non-delivery risks is the potential market response of increased delivery or availability from other units. In particular, we note that a market response from interconnectors is assumed in the procurement modelling under the non-delivery sensitivities. We find this needs more analysis. It implies that continental generators will over deliver or become more available as a response to non-delivery by some GB assets. This appears to be speculative.

Recommendation 60: The Root Sum of Squares or Simple Summation approach to multiple non-delivery risks needs to be fundamentally reconsidered in terms of the independence of the risks involved, or their dependence on common mode drivers, and their possible market responses induced. We suggest a more flexible rationale be developed based upon the characteristics of the different non-delivery risks.

Recommendation 61: An 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 CM auction clearing prices and average energy market prices.

54. Looking at over delivery, there remain the possibilities that the non-capacity market plants currently being built, such as renewables facilities, could increase their capacity and, for the capacity market purposes, over deliver, or that plant currently being delayed due to COVID-19 could catch-up with original construction plans. The next CfD allocation, depending on the technologies secured, could also potentially increase renewable capacity by 2024, and market changes, such as to ancillary services, may encourage more storage developments, DSR, etc., which could all reduce the capacity to be secured to meet the reliability standard. However, the PTE believes the sensitivities used by National Grid ESO have been robust given the current position of the market.

55. The PTE noted last year, and would like to reiterate, that National Grid ESO's forecasting of capacity requirements would be more robust if the capacity auctions were held earlier, i.e., in December each year, so that accepted volumes are known in time for the analysis. It may also help if a plant operator can surrender agreements it knows it cannot deliver earlier than the termination trigger date. Not only would this potentially inform the modelling work that underpins the ECR, it would, in our view, allow parties more time to deliver on agreements, reducing the non-delivery risks for new plant in particular. The experience with COVID-19 delaying construction, requiring Capacity Market rule changes to give greater flexibility over late delivery may not have been so pressing if parties were afforded the time to deliver as originally intended in the capacity market design.

56. National Grid ESO's assumptions on the behaviour of eligible capacity entering the Capacity Market, will be adjusted for known opted-out plant following the pre-qualification process. The PTE notes that holding the pre-qualification process earlier would provide more robust information before the Secretary of State sets the final auction parameters. For example, a new plant may pre-qualify, but then not post, or later remove, credit, thereby making it ineligible for the auctions. Ofgem's proposals to make pre-qualification evergreen may make this possible in future years. The PTE therefore hope Ofgem and BEIS will continue to work to move the whole Capacity Market arrangements to earlier in the year.

Recommendation 62: BEIS and Ofgem should consider the timing of all CM related activities each year in order to allow pre-qualification and auction results to better inform National Grid ESO's modelling, and give parties longer to deliver new build plant after the T-4 auction.

Domestic De-Rating Factors

57. National Grid ESO has used the same methodology for calculating the derating factors as last year and so there are comparatively few aspects to comment on. Taking the conventional plants, the main change is that this year the coal plants are split out from biomass steam plant. This reflects the decline in coal capacity and a further year of data for the biomass plant. Indeed, the data shows that biomass plant have a higher derating factor than coal plant at 89% versus 80%. This is counter to typical expectations, where biomass plant would normally have lower availabilities due to more complex fuel handling and combustion issues with variable fuel supply. Here, the data reflects the higher reliability of the big Drax converted coal sets as well as some poor availability figures on some of the coal plant ahead of their closure.

58. The data shows considerable variation in availabilities between years, especially for coal (61% to 91%) and biomass (77% to 94%). Nuclear plant availabilities have varied from 72% to 88%, with a generally declining trend, like coal. Gas plant dominated by CCGTs shows much less variability at 88% to 95%, but even the peak number achieved in 2016/17, is lower than what is typically recorded in many jurisdictions operating single buyer models with high penalties for unavailability.

59. For the variable renewable generation technologies – wind and solar PV – National Grid ESO uses the Equivalent Firm Capacity (EFC) approach as before. This is forward looking approach which simulates the value of each Variable Renewable Energy (VRE) technology independently using the Unserved Energy Model (UEM) to estimate the equivalent capacity of firm generation. As previously, wind has a much higher EFC than solar PV (which is to be expected given that PV is not available in the evening peak). Compared with last year's ECR the wind derating factors have all been reduced, especially for T-4, which has seen reductions of 2.5% and 1.5% for offshore and onshore respectively. The EFC for solar in the T-4 has risen by 1% to 3.3%, which National Grid ESO says reflects the interplay with electricity storage, which impacts the role PV can play in long duration outages. Whilst the PTE endorses the forward-looking, model-based approach to derive derating factors from EFCs, we think that sufficient data has now been accumulated to at least backtest these models and perhaps integrate a more statistical approach into the modelling.

60. Derating for batteries, which is also calculated on an EFC basis, shows moderate changes from last year's ECR, with derating factors slightly higher for the T-1 and slightly lower for the T-4. The maximum derating factor set by hydro pumped storage is

now achieved at 4.5 and 5.5 hours in the T-1 and T-4 auctions, versus 5 hours last year.

61. Derating for turn-down, demand side response (DSR) continues to be estimated based on the availability of non-BM STOR. There is a widespread view that DSR exhibits duration limits, either from genuine demand turndown capability or back-up generation. This remains on ESO's to do list, pending identification of appropriate data. The PTE suggest that, as with embedded generation, collecting more data on how DSR actually responds to market conditions may be useful.

Recommendation 63: A more thorough analysis of the duration limits for DSR (turn down) should be undertaken.

Interconnector De-Rating Factors

62. Interconnector analysis has always been challenging. Firstly, because of their nature: they are transmission links but inject energy resources into the GB network like generators. Secondly, because an assessment of their contribution under stress events is quite hypothetical as there is an absence of sufficient historical evidence on flows under stress. As a consequence, the resource contribution and derating factor analysis is essentially model-based. The PTE recognises the difficulties and has been generally supportive in the modelling improvements. This year, the modelling process is similar to 2020, based upon the DDM and Afry BID3 model, but with updated assumptions.

63. Following PTE55, we are pleased to see a more comprehensive listing of the assumptions in the Appendix of the ECR. We were also grateful for industry feedback on the methodology consultation issued by National Grid ESO earlier in the year. In summary, five responses were received. One was concerned about more transparency, the relative credibility of the sensitivities, a less pessimistic view of Belgian nuclear, an update of the technical reliabilities, the inclusion of strategic reserves and a clarification request that the GB stress period adjustments do not double count demand effects. Another provided a detailed summary of the hydro optimisation in Norway and argued against the risk of capacity shortage, as well as reiterating the need for timely transparency of assumptions. An academic working group advocated a longer weather dataset with climate change corrections, and also pointed to the credibility question in the modelling that neighbouring countries will continue to export up until the point of disconnections in their own countries. A further company observed that the Irish All-Island Statement does not take account of the most recent capacity contracts. And finally, a large company provided comments on the modelling limitations of BID3, suggested some backcasting validation, pointed to the technical (un)reliability of the links as well as offered some detailed comments on various specific assumptions. The PTE is grateful for all of these observations and have given them careful consideration.

64. The analysis undertaken by National Grid ESO using BID3 is based upon the capabilities of the interconnectors to deliver power into GB at times of stress. Thus, the modelling is necessarily contrived to create the stress. There are two aspects to the modelling. For the procurement targets, ESO model the interconnector flows with their own and Afry BID3 base cases assumptions, and scenarios, put these results into the DDM and calculate an EFC for total interconnection. There is an uplift on GB demand to try and get the GB LOLE close to around 3 hours. This is because the interconnector flow distribution in the Dynamic Despatch Model (DDM) is a function of system margin, so the DDM needs data points that cover the full range of margin (as set out in EMR 72 development project). The DDM uses this to calculate an EFC. This effectively provides a total derating factor for the interconnections, and is reported in Appendix 4.4 of the ECR. The PTE considers that in future, this implicit total derating factor be made more prominent in the analysis so that consideration can be given to the consistency between its use in the procurement analysis and the separate determination of individual country derating factors, as described below.

65. The modelling section on individual interconnector derating factor estimation is slightly different. GB demand is again scaled up, and the same Afry base case is assumed, but in the scenarios that relate to each country meeting its reliability target, continental thermal supply is scaled down to simulate the 3-hour LOLE stress situations in those countries. Last year, the PTE placed most emphasis upon the scenario that related to the harmonised ENTSO-E targets, since that provided a coherent policy framework. The PTE is however aware that several countries have resources in excess of these targets and that even with impending capacity markets causing a procurement at these targets, their available supply may higher. There are good reasons therefore to consider outcomes above the ENTSO-E targets. Alternatively, with under delivery scenarios for French nuclear, there are prudent considerations of under-delivery against these targets. The result of this modelling, under the various FES scenarios and sensitivity assumptions, are very wide ranges reported in the ECR for our consideration.

Recommendation 64: The consistency of the implicit derating of interconnectors for the DDM procurement analysis and the determination of individual country derating factors should be made more transparent.

66. In addition to derating the economic flows, PTE requested transparency on the technical deratings subsequently applied to these figures by BEIS. We have examined these and note that they are currently being updated.

67. In our deliberations on the ranges of derating factors produced in the ECR, we have followed the same principle as last year, in terms of anchoring upon the ENTSO-E target scenarios. We are mindful of the risk posed by French nuclear outages, as last year, but also the headroom that several countries are likely to have above their reliability targets. The latter point being particularly relevant to Ireland. We are aware of the future plans from ENTSO-E and ACER for direct participation by generators in

cross-border capacity remuneration schemes but have taken the view that GB will not be involved in this for T-4 and that within the EU, it should not fundamentally change the capacities for interconnector flows. Similarly, the loss of market coupling post Brexit, whilst increasing trading frictions, has not been deemed detrimental to the GB imported resource availabilities at times of stress. Further consideration of loss of trading efficiency at short notice (e.g., 4 hours for a capacity market event) should be monitored.

68. The PTE is also aware of the previous "cannibalisation" modelling which suggests that, as more interconnector capacity becomes available, individual derating factors will systematically fall. Finally, being a model-based analysis, the PTE is cautious about model risk. All models are simplifications, and we consider, on balance, that real-world frictions are likely to create flows somewhat below those derived from the modelling. Nevertheless, in the commentaries provided by National Grid ESO in the ECR, and with the use of Afry base case assumptions, there are, in some cases, compensating factors lifting the derating factors to be a little larger than last year. Taking all of these factors into consideration, we have proposed for consideration the following derating factors (with our 2024/25 recommendations for comparison):

PTE Recommended Country De-rating Factors		
	2025/26	**2024/25**
Ireland	50%	50%
France	76%	76%
Belgium	66%	69%
The Netherlands	68%	63%
Denmark	69%	57%
Norway	91%	99%
Germany	61%	n/a

69. For Ireland, in the ECR, the maximum is 97% whilst the minimum is 10%. We note that the European LOLE standard simulations are close to the minimum. Last year we recommended 50% for 2024/25. On balance we are proposing the same value. Whilst Ireland has an LOLE standard of 8 hours, if that were met, it would lead to very limited flows to GB. However, we expect that excess capacity above this target will persist.

For comparison, in the 2019 All-Island Generation Capacity Statement, a derating factor of 60% is used,[4] although of course for flows in the opposite direction.

70. For France, in the ECR, the maximum is 97% whilst the minimum 40% is the 12GW French nuclear outage sensitivity. The EU LOLE standard simulations give 80% under the Base case assumptions. On balance we recommended 76%, the same as last year. Within the scenarios, there is an assumption that not all French DSR may be available at times of GB stress. We find this may need more research to test this assumption.

Recommendation 65: Further analysis of the availability of DSR and Embedded Resources in Europe at the times of GB stress should be undertaken.

71. For Belgium, the maximum is 82% whilst the minimum 22% reflects the Belgian nuclear closure. We are inclined towards the EU LOLE standard simulations giving 66% under the Base case assumptions.

72. For The Netherlands, in the ECR, the maximum is 88% whilst the minimum at 36% is the 12GW French nuclear outage sensitivity. We are inclined towards the EU LOLE standard simulations giving 68% under the Base case assumptions. This compares with 63% recommended by us last year for 2024/25, noting the additional capacity identified in the ECR report.

73. For Denmark, in the ECR, the maximum is 87% whilst the minimum is 35% with the 12GW French nuclear outage sensitivity. We are inclined towards the EU LOLE standard simulations giving 69%. This compares with 57% recommended by us last year for 2024/25, recognising assumptions about higher capacity than in lasts year's ECR.

74. For Norway, in the ECR the maximum is 96% whilst the minimum is 72% in spill over of the 12GW French nuclear outage sensitivity. Whilst the EU LOLE standard simulations give 82% under the Base case assumptions, we do not consider such a drop from last year's 99% is justified. We therefore recommend 91%.

75. Germany only appears under the Leading the Way scenario and so there is no Base Case. The European standard under the scenario is 61%. Leading the Way was excluded last year and so there is no comparison.

[4] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

Methodology

76. The PTE has always made a number of recommendations in its previous reports. Last year's (2020) PTE report made 6 new recommendations, numbered from 52 to 57 (continuing on from the previous years' numbering). All these recommendations, along with others raised by BEIS, Ofgem and National Grid ESO's internal post review/update process were considered by National Grid ESO.

77. National Grid ESO assesses which recommendations to pursue, delay or, in effect, reject by using a multi-criteria scoring system. This gathers a number of projects that have been suggested by National Grid ESO itself, BEIS and Ofgem as well as our recommendations and ranks them for action within limited resource and time constraints, according to subjectively awarded scores against the criteria of "Impact / Materiality", "Effort/Resource" and "Priority", with Priority being double-weighted. BEIS consults the PTE on scores, but the PTE is not involved in the final selection.

PTE 2020 Recommendations which led to development projects with the outcomes accepted and implemented	**PTE Comments**
Recommendation 53: As new data on embedded generators becomes available, consider specific derating factors for embedded plant types.	The PTE welcomes the Embedded Asset Registers but remains concerned that the data National Grid ESO relies on for forecasting embedded plant remains less robust than that which it has for transmission connected assets. We are disappointed National Grid ESO has not found a way to secure better data on embedded plants, for example raising rule changes to the DCUSA or CUSC to require the provision of real time data on at least the larger embedded plants. Until this data starts to be collected the market will not understand the full scale of over/under delivery from this section of the market and the de-rating factors applied to embedded assets will be less accurate.
Recommendation 54: Future ECR analysis of Base Case and over-delivery sensitivities should explicitly take note of the fact that not all eligible plant will either enter the CM or close.	The project has been completed and its recommendations have been taken into account in the amount of over-delivery assumed in the Base Case. National Grid ESO should keep this under review as it is the older kit that will not take agreements and stay open – of which we have increasing volumes.

PTE 2020 Recommendations which led to development projects with the outcomes accepted and implemented	PTE Comments
Recommendation 55: List the modelling assumptions and limitations that might bias the interconnector ratings either up or down and comment on their materiality.	Further detail on modelling assumptions is included in Annex A10, and National Grid ESO has invited feedback on the additional information published. The PTE are pleased to see a more comprehensive listing of the assumptions, and we were also grateful for industry feedback on the methodology briefing issued by National Grid ESO earlier in the year.

PTE Previous Recommendations Not Taken Forward	PTE Comments
Recommendation 52: The factors affecting the evolution of peak behaviour should be analysed more explicitly from the broad perspectives of current and future technical, society and regulatory evolutions.	This recommendation followed on from the 2019 PTE Recommendation 44 on load shape evolution (not taken forward). Many factors affect the evolution of both average and peak demand, but there are some factors that will particularly affect the peak to average ratios. This was clear from behaviour during the COVID-19 pandemic, when peak demand fell by less than average demand. We accept that the COVID-19 pandemic has made demand forecasting particularly challenging this year; but a long-term issue remains the factors affecting the relationship between average demand and peak demand. Recommendation PTE44 of 2019 was intended to provide a more explicit analysis of the potential load shape evolutions and their implications for peak demand. This recommendation was not taken forward in 2019/20. Recommendation PTE52 of 2020 was a revised and expanded version of Recommendation PTE44 and suggested that 'The factors affecting the evolution of peak behaviour should be analysed more explicitly from the broad perspectives of current and future

PTE Previous Recommendations Not Taken Forward	PTE Comments
	technical, society and regulatory evolutions'. The impact of COVID-19 has increased further the importance of Recommendation PTE52. It was encouraging to note that some progress has been made on addressing Recommendation PTE52 but work has yet to commence on some important elements of the work plan.
Recommendation 56: The Technical Reliability of HVDC links should be considered more fully and whether the technical reliability of interconnectors, and perhaps private links to large offshore wind farms, should become more explicitly part of the procurement methodology in future.	Recommendation 56 falls within the remit of BEIS rather than National Grid ESO.
Recommendation 57: We recommend that National Grid ESO undertake a fundamental analysis of the sequential nature of the capacity procurement, taking account of the appropriate caution needed in relation to the quantifiable and unquantifiable uncertainties, risks and their consequent costs.	The procurement methodology, which uses a Least Worst Regret (LWR) criterion, produces a capacity-to-secure which is deliberately cautious with respect to the uncertainties and risks in achieving the LOLE target of 3 hours. Last year the PTE raised concerns that failing to take into account uncertainty and the opportunity to react to it in the later T-1 auction might cause an additional upward pressure on procurement: essentially errors in only one direction can be corrected at the later T-1 auction. The PTE agrees that this is a more complex task than initially envisaged and agrees that it should be explored further. Some of the recommendations elsewhere in this Report will help prepare the way: Recommendation 58 on short-term uncertainty around the Base Case; and any changes to Capacity Market rules which allow earlier signalling of non-delivery or non-availability.

78. The Least Worst Regret (LWR) outcome is essentially determined by the most pessimistic and the most optimistic of the scenarios and sensitivities considered. This year the capacity-to-secure for both the T-4 and the T-1 auction were determined by a pessimistic sensitivity for non-delivery and an optimistic sensitivity for over-delivery. We are concerned that the extent of over- and non-delivery has become so large that the market arrangements to provide a regular retainer payment to reliable forms of capacity in return for such capacity being available when the system is tight, may not be operating efficiently. If the market arrangements are failing, the modelling assumptions in the ECR are undermined.

Conclusion on Target Capacities

79. 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. We endorse its fitness-for–purpose. We recognise the market has altered significantly since the Capacity Market started and therefore the modelling challenges have changed. We wish to express our appreciation of the constructive manner through which National Grid ESO and BEIS have engaged with the PTE.

80. For T-1, we accept the 4.5GW recommendation in the ECR but register concern that it will be a higher procurement than recent T-1 auctions and may lead to a high clearing price. There is a concern about liquidity, but awareness of this need to procure may attract more facilities to pre-qualify. Nevertheless, we recommend a detailed reconsideration of the base case supply-side assumptions and non-delivery sensitivities in the autumn. The 4.5GW is 2.4GW above the base case as a consequence of the LWR criterion, driven mainly by the 5.2GW non-delivery sensitivity. We did address whether this may be an over-reaction to the events of the most recent winter, but the plant-by-plant risk analysis does provide credibility. The move away from using RSS to a simple summation of multiple plant risks has also increased the non-delivery sensitivity. We recommend further clarification on the rationality of this before the autumn adjustment. We note that if the 5.2GW and 4.8GW non-delivery sensitivities were to be excluded, the procurement would be 4.1GW. We believe more clarity on this could be achieved before any autumn adjustment.

81. For T-4, we accept the 44.1GW recommendation in the ECR but also register concern that it will be a higher procurement than recently seen. The 44.1GW is well above the base case of 41.3GW as a consequence of the LWR criterion, again driven mainly by the extreme non-delivery sensitivity. The move away from using RSS to a simple summation of multiple plant risks has again increased the non-delivery sensitivity and as with the T-1, we recommend further clarification on its rationality before the autumn adjustment. We also note that the peak demand adjustment is influential, and we have recommended a closer look at the drivers and uncertainty of forecasting. Thus, we recommend a detailed reconsideration of the base case supply-side assumptions and non-delivery sensitivities in the autumn. A substantial set-aside may also be prudent since the 44.1GW, if confirmed, is 2.8GW above the base case expectation.

82. Thus, without having direct evidence to suggest reductions to these targets, the PTE is concerned about potential over procurement and the consequent costs to society. We anticipate that more information will become available in time for any autumn adjustment and that a careful re-evaluation of the supply-side of the base case and non-delivery assumption be undertaken. In particular, we have been informed that the Ofgem review of market responses during the past winter will be available in time for this, as well as through the pre-qualification process and additional data on terminations.

Quality Assurance

83. Previously followed procedures continue to provide QA and these are closely aligned with BEIS's 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.

This publication is available from: www.gov.uk/government/publications/national-grid-eso-electricity-capacity-report-2021-findings-of-the-panel-of-technical-experts