Department for Business, Energy & Industrial Strategy

PANEL OF TECHNICAL EXPERTS

Final Report on National Grid's Electricity Capacity Report

July 2017

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Executive Summary and Recommendations

1. The role of the Panel of Technical Experts (“PTE”) is to impartially scrutinise and quality assure the analysis carried out by National Grid (NG) for the purposes of informing the policy decisions for the Capacity Market. In fulfilment of this role, we have scrutinised National Grid’s 2017 Electricity Capacity Report on the target capacity for the T-1 Auction for delivery year 2018/19 and the T-4 Auction for the delivery year 2021/22 and this document presents our findings.
2. In our previous reports (2014-2016), we made 25 recommendations in total (of which 10 were from 2016) for improving the methodology and reliability of the modelling by which target capacities are calculated. National Grid has taken action on many of these as we report in Annex 1. We welcome National Grid’s improvements to its DDM (Dynamic Dispatch Modelling) and the new European-wide modelling of interconnector flows and de-rating, and various data refinements. However, we note that recommendations concerning demand response from scarcity pricing, or potential of ‘emergency’ demand controls by Distribution Network Operators (DNOs), have not so far been prioritised (Annex 1).
3. The PTE has had considerable exchange with National Grid, BEIS and Ofgem in the process of National Grid putting its Electricity Capacity Report together and we are content this presents a sound piece of analysis. As usual, we make a few recommendations for future work.
4. However, this year we also take a slightly different view on the recommended capacity to procure:
   - **T-1 auction for Winter 2018/19:** National Grid have recommended procuring **6.3GW,** based on a number of technical adjustments (with which we concur) combined with changes in expected demand and concerns about non-delivery of capacity procured in the first Capacity Market auction. Our advice is that the Security of Supply standard could be met with **not more than 6GW**.
   - **T-4 auction for Winter 2021/22.** National Grid have concluded that **50.5GW** should be procured in the Winter 2021/22 auction, based on the prescribed methodology. PTE believes that the volume need be **no more than 50GW**.

   For the T-4 auction, should the government wish to keep with the National Grid recommendation of 50.5GW, we believe the government should consider deferring more of that capacity to the T-1 auction in 2020, by which time key uncertainties around demand and non-delivery should be much clarified.

5. This difference to the National Grid recommendations arises from the PTE taking a less conservative view in two main areas:
   - *Non-delivery of existing Capacity Market contracts*. Upon its initial presentation we accepted NG's proposal to model up to 4GW loss of CM capacity as being within the plausible range, but continued to probe this and subsequently came to the view that 3.6GW, not 4 GW, would be a more appropriate estimate of the maximum collective risk of non-delivery of contracted CM capacity, particularly as applied in the LWR methodology.[1] Although we recognise there are several potential sources of non-delivery (coal, embedded generation, battery ratings, and DSR), and largely accept Grid's judgement of the individual component risks, these are not additive and indeed, loss of one would increase the incentives on others to remain on the system and fulfil their capacity contracts.
   - *Response of demand to peak prices.* Building on our discussion in last year's PTE report, we believe the demand projection does not take sufficient account of the demand-side response (DSR) to peak prices. The PTE's view is that DSR will be enhanced over time by increased 'smart response' capability and higher cash-out prices in the balancing mechanism (due to raised price cap and other reforms), and that not all the Industry and Commercial sector (I&C) potential can be allocated to Capacity Mechanism bids (and hence, taken out of the underlying demand projections). I&C demand-side response that does not participate in the CM could either be taken off the underlying demand projections, or treated as a form of non-CM capacity and be subtracted from the target capacity.
6. We believe that either of these considerations imply that the Security Standard for 2021/22 could be adequately met with *c.* 0.5GW less than recommended by National Grid, and consequently that they comprise a compelling rationale for concluding that the security standard could be met in the T-4 auction with no more than 50GW procurement. Our reasons concerning the T-1 auction are similar and spelt out in the body of this report.
7. As requested, we have proposed specific derating factors (DRFs) for interconnectors, informed by the ranges of potential DRFs proposed by National Grid, and detailed our reasoning behind the proposed numbers. We have paid additional attention to the two interconnectors to Ireland, for reasons indicated; we offer DRFs for Moyle (Scotland-Northern Ireland) and EWIC (Wales–Irish Republic) separately for multiple reasons indicated, including internal

[1] In last year's report we demonstrated how, by just halving the probability assigned to the highest non-delivery, would reduce the requirement by 0.6GW (PTE 2016, p.45). Our own enquiries concerning the volume of embedded generation that may be lost due to Ofgem's introduction of transmission charges helped to modify our initial levels of concern, but this remained a source of widely varied estimation.

transmission constraints which affect the capacity available on both sides of the links;[2] varied histories of technical failures; and the potential uncertainties about the integrated operation of the Single Electricity Market in Ireland, including possible impacts of Brexit. We recommend (recommendation no. 33) that this separation of the two Irish interconnectors becomes standard for future assessments.

8. The increasingly rapid changes in the GB electricity system poses challenges for evaluating the appropriate capacity to procure, and even the metrics by which to judge this. Thus, we welcome the government's five–year review of the Capacity Mechanism. As a contribution to this, we include Annexes relating to data on embedded generation (Annex 2), and a more in-depth look at some of the underlying issues relating to extreme events, stress periods and the Value of Lost Load (Annex 3).
9. Due largely to the growth of embedded generation (connected at distribution level), demand on the transmission system is declining, with a growing divergence between this and the final demand. But data on distributed generation (changing patterns of end-use load and behind-the-meter generation) and other forms of Distributed Energy Resources are presently inadequate. Ensuring adequate data availability across the entire electricity system, both for National Grid and for public understanding and scrutiny, is a high priority. There are also related issues to consider on how this data may inform derating factors for embedded generation, in which storage also poses special challenges (Annex 2).
10. The system has growing flexibility to deal with potential supply 'shortfalls' in ways which do not lead to involuntary disconnections. This is partly through more price-responsive demand and greater utilisation of distributed generation, industrial backup and storage at many levels; and partly through a range of options available to the System Operator and Distribution Network Operators to deal with stress events. Some but not all of these flexibility resources may participate in the Capacity Mechanism. These developments imply an evolution of the concept and valuation of what are currently termed 'loss of load events'. We welcome the forthcoming review of the Value of Lost Load and its application (as part of BEIS' review of the Reliability Standard), as an important contribution towards this. (Annex 3).

[2] The availability of power imported through the Moyle interconnector to the rest of GB is heavily constrained by local transmission constraints within Scotland; some uncertainties remain about the timing and utilisation of the internal north-south interconnector within Ireland.

New Recommendations

The new recommendations in our report are listed below. (The numbering of the recommendations follows on from the 25 recommendations in our previous reports).

Introduction

Role of the Panel of Technical Experts

11. The Government commissioned, commencing in February 2014, through an open and transparent procurement process, an independent Panel of Technical Experts (the PTE) for the enduring Electricity Market Reform (EMR) regime. The role of the PTE is to impartially scrutinise and quality assure the analysis carried out by National Grid in its role as Delivery Body for the Capacity Market.
12. 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 fourth report, focused on scrutinising the analysis that informed National Grid's 2017 Electricity Capacity Report. The report covers the National Grid recommendation to the Secretary of State on the recommended capacity to secure for the 2021/22 T-4 auction as well as the recommended capacity to secure for the 2018/19 T-1 auction.
13. The background of the members and terms of reference of the PTE are published on the Government website.[3]
14. This report has been prepared for BEIS by:
    a. Professor Michael Grubb (Chair)
    b. Andris Bankovskis
    c. Dr Guy Doyle
    d. Professor Goran Strbac
    e. Professor Derek Bunn

Scope

15. The scope of the PTE's work is to impartially scrutinise and quality assure the analysis carried out by National Grid for the purposes of informing the policy decisions for the Capacity Market. This includes scrutinising: the choice of models and modelling techniques employed; the inputs to that analysis (including those BEIS provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The PTE will review whether the analysis is robust and fit for the purpose of Government taking key policy decisions. This will include, for example considering potential conflicts of interest National Grid or others involved might have in influencing the analysis.

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

16. The PTE has no remit to comment on Capacity Market policy 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. 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, for example, on the Reliability Standard to be set by Government or the mechanisms chosen to achieve its objectives.
17. For the last two years, as a result of legislative changes on eligibility, interconnectors have been allowed to participate in the Capacity Market, and that remains true for 2021/22 delivery, although they remain as virtual participants in the 2018/19 delivery year where their contribution is netted off the target. This report will also comment on the ranges that National Grid have recommended for each interconnector from which the Secretary of State has chosen the final de-rating factor.

Approach

18. During the course of the PTE's work, National Grid has presented its methods, assumptions and outputs in relation to National Grid's core task of recommending the auction target capacity in the Capacity Market and the PTE has had opportunity to question National Grid during the development of its analysis and recommendations.
19. To carry out its work, the PTE met with National Grid, BEIS and Ofgem at BEIS's offices, approximately on a monthly basis since January, during which presentations were made by National Grid and the PTE had an opportunity to ask questions and make comments. Subsequent to the meetings, the PTE provided various interim views and put many questions to National Grid to which BEIS organised responses.
20. The PTE's initial focus was on gaining an understanding of the methodologies and analytical techniques available to National Grid to address the additional aspects of the next auctions.
21. The PTE has generally focussed more closely on the areas that appeared to be of highest impact and greatest uncertainty, providing comment and analysis to support the PTE's developing views. Key areas that emerged included:
    a. The potential non-delivery of plants with capacity contracts, particularly some coal plants and risks to embedded generation following the decision by Ofgem on a reduction of 'Embedded Benefits' (i.e. application of transmission charges to generators connecting below the level of the main transmission system).

b. The de-rating of interconnectors
c. The ‘Least Worst Regret’ methodology for selecting procurement, particularly relating to the reliance on Base Case and one or two dominant sensitivities, in the context of wider options for managing any system stress
d. The continued inadequacy of reliable data on embedded generation
e. The treatment of energy demand including the potential response of demand to wholesale prices, taking account of the above

22. As required by the PTE’s Terms of Reference, the PTE also kept in mind the potential for National Grid to be confronted by potential conflicts of interest. The PTE, throughout this process, has sought to mitigate this by vigorously challenging assumptions. We note that National Grid would bear some of the loss of reputation for any blackouts, and bears none of the cost of over-securement, 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 to believe that National Grid has exploited its privileged position and hence there has been no observed conflict of interest up to the time of writing this report.

23. This report is not comprehensive and nor is it a due diligence exercise but the PTE believes that it has nevertheless identified some important issues that have significant consequences. Accordingly, and in line with our approach in previous years, the PTE has not overly focussed its attention in this report on the many details of various matters which were raised and satisfactorily resolved or are part of on-going development.

24. This report has been prepared from information provided by BEIS, National Grid and Ofgem and the collective judgement and information of its authors. 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 or organisation considering investment must make their own independent assessment having made whatever investigation that person or organisation deems necessary.

Observations on and Context Provided by Auctions since Last Report

25. To understand the significance of auction results to date, it is important to be aware of the auction and target capacity-setting design. **First,** plant that has a low-carbon or renewable contract (ROC or CfD) cannot participate in the auctions, but has their equivalent firm contribution deducted from the target capacity. National Grid discusses how to make allowance for the contribution of wind in extreme cold weather events in the ECR. **Second,** plant that has opted out and stated to be operational in the delivery year at the T-4 auction stage has its de-rated capacity deducted from the target capacity. **Finally,** capacity that already has a CM agreement covering the delivery year in question (e.g. from 15-year contracts awarded in prior auctions) is normally deducted from the remaining target capacity, unless it is clear that it has cancelled that agreement or is at high risk of doing so before the delivery year.
26. We have now seen the results of three T-4 capacity auctions held in 2014, 2015 and 2016 (for delivery years 2018/19, 2019/20 and 2020/21) which have cleared at £19.40, £18.00 and £22.50 a kW a year, respectively. These prices are all well below the net assumed cost of new entry (CONE) of £49.00/kW/yr, which is used to locate the position of the demand curve for capacity. There has been significant liquidity in all these auctions, with most of the awarded capacity going to existing plant. Awards for new capacity have been dominated by smaller, generally distribution-connected gas and diesel capacity ("embedded generation"), rather than conventional large transmission connected CCGT or OCGTs, which have been notable by their comparative absence of success (in the latter case, illustrated by Trafford CCGT which was awarded a CM agreement in the first T-4 auction, but later retracted).
27. There have also been two TAs (Transitional Auctions) specifically for Demand Side Response in 2015 and 2016, which produced prices clearing at £27.50 and £45.00/kW/yr, respectively. The later auction price was clearly impacted by including only 'turn-down' DSR, not distributed generation, which also reduced liquidity[4].
28. More recently, there was a special one-off Early Auction, eligible for generation, storage and DSR in early 2017, for delivery next winter (2017/18), which cleared at

[4] https://www.ofgem.gov.uk/publications-and-updates/annual-report-operation-capacity-market-201617

just £6.95/kW/yr. This auction was run as an alternative to extending the transitional strategic reserve arrangements for generators (DSBR), and the low price has been attributed to the fact that many of these generators already had capacity contracts for the subsequent year and thus needed little incentive to confirm availability for 2017/18.[5]

[5] https://www.ofgem.gov.uk/publications-and-updates/annual-report-operation-capacity-market-201617

Analysis and Key Findings

National Grid's Recommended 'Target Capacity'

Introduction and context

29. As in its previous ECRs, NG lays out its modelling approach and its scenarios and sensitivities that will frame its findings on the amount of capacity to secure in the auctions. The methodology is essentially unchanged from previous years, scenarios and sensitivities have been updated as discussed in the following sections. Nevertheless, clear challenges remain particularly in the context of the rapid evolution of the GB electricity system and the potential this offers for managing security more cost-effectively.

Demand Forecasting

30. Forecasting peak electricity demand is one of the fundamental elements in the analysis of future capacity requirements. Last year, consistent with our recommendations, National Grid moved to focus all their formal quantitative appraisal for the ECR around their Base Case projections, which they conduct under the Peak National Demand Forecasting Accuracy (DFA) Incentive. This is likely to be the best available single NG projection, and we note that it falls within the range of NG's four Future Energy Scenarios (FES).
31. Whilst the four FES scenarios provide a broad perspective on the longer-term potential futures, their role in the subsequent analyses is actually minor. The crucial methodological element for the subsequent calculations of the capacity to procure is the short-term Base Case, together with its sensitivities. Our comments on the methodology and sensitivities are contained in the following two Sections.
32. The Base Case is a bottom-up feed forward projection of current trends supplemented with market information. We are reassured that this is subjected to quality assurance through the DFA incentive on demand forecast accuracy for 1 to 4 years. A separate letter is published on the National Grid website as a licence obligation and explains how NG is developing its demand forecasting process. In future ECRs it would be preferable to have a closer link-up in this regard with a review of previous performance contained within the report.

New Recommendation 26. National Grid should seek to include a review of their past forecasts, focusing particularly on periods of peak demand and system stress, as a regular item, along with key points from their Demand Forecasting Incentive report, which could be included along with the other Quality Assurance notes.

33. We note the work undertaken this year to improve both the demand forecasting and CM de-rating factors of small scale, distribution-connected generation. The introduction and continued build-up of embedded generation increases the disparity between underlying demand and that registered at transmission level. Understanding this requires greater access to distribution level data by National Grid. As an interim measure, National Grid this year purchased data from ElectraLink on distributed generation by technology. The current ECR reports that this data has clear quality and aggregation issues and National Grid is exploring ways to augment this (Annex 2).
34. The situation is expected to improve, since the industry (BSC) Panel has approved a Modification (P348[6]) which will enable National Grid to receive gross export and import metered data for embedded generators. However, this modification is cast in the context of collecting data to support Ofgem's decision to apply transmission (TNUoS) charges to embedded generators. This should help with understanding trends in both embedded generation and demand, after its introduction in February 2018, but it remains to be seen how comprehensive the data are for these purposes and for related matters such as estimating derating factors of embedded generation (Annex 2).

New Recommendation 27*.* Improving data and providing access to the best available data on embedded generation (including for National Grid) should be prioritised as a matter of urgency, if possible before next year's ECR.

35. Embedded generation is one key form of 'Distributed Energy Resources', which may also comprise local storage and demand-side response. In Annex 2 we consider additional dimensions of these. Distributed Energy Resources have the benefit, relative to transmission connected units, of typically incurring less line losses[7]. This does not appear to be credited in GB in currently used methodologies (though it is in some US systems), but may become increasingly significant, equivalent to several hundred MW. Many small units may also have aggregate contributions to security that differ from equivalent capacity of large units, whilst

[6] https://www.elexon.co.uk/mod-proposal/p348/

[7] In some circumstances, for instance when a distribution region has an excess of generation over demand, and power flows up the voltages levels, overall losses may increase, although this is likely to be comparatively rare at peak demand periods.

storage has special characteristics related to the limits on the storage 'tank'. In Annex 2 we explore these further leading to recommendation 28:

New Recommendation 28. We recommend that National Grid develop a derating methodology for energy storage that considers the size of the storage tank in relation to derating factors; In addition, National Grid should consider the extent to which Distributed Energy Resources (including embedded generation, energy storage and demand side response) incur lower network losses and the possible implications of this for the estimation of de-rating factors.

36. In last year's report (PTE 2016) we suggested that the demand scenarios do not adequately allow for demand-side response (particularly arising from scarcity pricing in intra-day market and balancing market operation). Historically, the great majority of demand-side response has come from the industry and commercial (I&C) sectors, amounting to about 1.3GW in recent years, and this does rise in the National Grid Base Case and FES Scenarios (to 2.1GW in the Base Case), along with an estimated 0.3GW of peak-price-response in the domestic sector. However it is assumed that all the I&C demand response can participate in the Capacity Mechanism and hence, to avoid risk of double counting, that part is not deducted from the Base Case projections used to estimate the capacity to procure. The rapid growth of smarter meters and controls should enable bigger responses in all these sectors, but we take the view that a significant portion of the I&C potential may not bid into the CM, for various reasons, but would still respond to high market electricity prices – particularly given the changes which could lead to substantially higher and more volatile Imbalance Prices[8] from November 2018. Drawing upon the analysis last year and ongoing work, we believe that the volume required to procure in the Capacity Mechanism arising from these factors could reasonably be on the order of about 0.5GW lower than the NG assumptions.

New Recommendation 29. We reiterate the importance of our previous recommendation no.23 (PTE 2016): "Analyse the impact of scarcity pricing on peak demand and also examine demand responses to high prices in markets that have already begun to roll out active management tools." and suggest that this be prioritised for development prior to next year's ECR, and extended to consider evidence around the extent to which different segments of potential demand response might or might not participate in the CM.

37. These various factors relating to the projection of peak electricity demand in the Base Case form one of the two principal rationales for our conclusion (section,

[8] When the VoLL in the Reserve Scarcity Pricing formula doubles from £3000 to £6000, the calculation becomes based upon the single marginal unit (rather than the average of the marginal 50) and the LoLP (loss of load probability) parameter becomes fully dynamic

"Comments on Target Capacity") that the Security Standard could be reasonably met with a somewhat lower procurement volume than recommended from the methodology employed by National Grid.

Least-Worst Regrets Methodology and its relationship to Base Case Demand Forecasting

38. No methodology is perfect. As with the FES modelling, modelling of the Base Case is based on an estimated distribution of demand, but does not involve probabilistic representation of *peak* demand in the DDM. Instead, uncertainties are modelled through the range of externally specified sensitivities. We have noted that the Base Case demand projection is within the range of National Grid's four FES scenarios but most demand response (to peak prices) is assumed to be allocated to the Capacity Mechanism (rather than being netted off demand projection). Projections are not yet systematically complemented with an ex-post review of past forecasts.
39. The application of Least Worst Regret to test sensitivities around this base case is the central methodology. National Grid followed our recommendations to further explore the possibility of conducting probabilistic assessments, noting the complexities and limitations of this.
40. The tests are for the most part based on recent history; 11 years of demand data is used, although 7 years is used for calculating plant and interconnector de-rating factors (which is what the CM rules mandate). National Grid only includes single parametric sensitivities, so combined sensitivities are not included, on the basis that the probabilities of such events are very small, and therefore would set too extreme outliers which might distort the LWR analysis. Sensitivities tested include uncertainty in weather - cold/warm winters, high and low wind at peak demand times, peak demand, over delivery of (non-CM contracted) capacity and non-delivery of contracted CM capacity. In each case, to ensure balance, sensitivities are typically run in pairs with both a high and low variant run. NG's academic advisors on this issue (Wilson and Zachary) have indicated that NG's approach here is logically consistent.
41. We support this conclusion. Nevertheless, their exploration does not resolve the fundamental problem that the LWR methodology, based around a single Base Case, means that results are determined by just a very few choices – namely the Base Case projections and the two most extreme sensitivities – which inevitably have a considerable degree of subjectivity.
42. As a possible contribution to the forthcoming 5-year review, in **Annex 3** we set out some wider considerations which could help to significantly reduce some of these methodological dilemmas, including consideration of applying weights to the extremes of the sensitivity ranges in the LWR, and by paying closer attention to the structure and potential responsiveness of demand, and the other sources of flexibility in our evolving electricity system.

Sensitivities

43. During the preparation for the 2017 ECR, the choice of sensitivities (described in detail in the National Grid report) was discussed with National Grid and agreed between National Grid, BEIS and the PTE prior to modelling. Some uncertainties and issues in particular around the non-delivery sensitivity are indicated below. The following summarises these and our key observations.
44. NG runs a number of sensitivities around its Base case to 2021/22 (and the Steady State scenario beyond this), rather than running them around each of the four FES. This reduces the number of sensitivities and also the range, however for a five-year horizon considered in the ECR, we endorse NG's approach.

1.1 Low and high wind at times of cold weather

45. Analysis of GB historical wind patterns shows some weakening in the general linear correlation between demand and wind at high demand periods. NG's central case applies scaling factor on wind output where demand exceed 92% of peak that increases linearly to 0.9 at 102% of peak. The low wind sensitivity assumes a greater decoupling to 0.8, while the high wind case applies no scaling factor. This seems a reasonable approach, although we note the impact is likely to be less pronounced running this variation on the Base case than the Two Degree scenario, which have significantly higher contribution from wind.

1.2 Plant availabilities

46. NG has run availability sensitivities for 2018/19 only, as it finds there is no material impact in 2021/22. This reflects NG's reliance on history. It applies a symmetrical variation equal to one standard deviation for both CCGTs and nuclear (which works out to +/-3% and 4% (percentage points) respectively.
47. The PTE's view is that the historical data may not be the best guide to future availabilities, as the future regime with CM in place should sharpen the incentive regime for generators. Coupled with the expected increase in incidence of high peak prices (arising from cash-out reform and increased volatility due to variable renewable supply) it would be reasonable to expect peak period availabilities to increase. For instance, portfolio generators are more likely to arrange their outage schedules to ensure higher availability at peaks.
48. On the other hand, while the incentive to make plant available during peak demand periods is projected to increase (due to expected higher CM prices, higher peak energy and balancing prices) there is a question whether an increasing number of old coal and CCGT stations will suffer decreasing reliability and hence availability due to degradation from wear and tear (especially as maintenance is paired back due to low margins, and as plant operate in peaking and back-up mode). Many experienced plant engineers and managers are concerned reliability could fall

markedly across these fleets and this could have a material impact to the extent these plants remain part of the fleet, rather than being decommissioned.

49. Consequently, we are content with the availability assumptions based on current evidence, noting also that the impacts on capacity procurement volume for the range of plausible uncertainty are not material.

1.3 Weather

50. NG's weather sensitivities include the lowest and highest peak demands observed in the last 11 years, which were 2006/07 and 2010/11 respectively. These winters represented a 1 in 14 years and a 1 in 9 year events respectively, according to National Grid's analysis. NG points out that the Met Office itself uses 30 years when calculating average temperatures. For its gas adequacy planning NG uses a 1 in 20-year standard, which reflects the fact that gas demand is very strongly correlated to temperature.

51. Interestingly, NG cites a further justification to the selection of the cold weather sensitivity as "reputational", in the sense that it would be difficult to exclude a low probability outcome, if it had occurred recently. This raises the question of whether, if for example two power stations were struck by lightning in a freak storm, planning standards would need to be revised to include such an event, or would a dispassionate probabilistic approach rule this out as an outlier. The fact that extreme events happen does not in itself change the likelihood of them happening. However, it is well known in behavioural and psychological sciences that it can have a dramatic impact on the personal and public perception of the risk.

52. We presume this is what NG have in mind in referring to "reputation", but there is a risk that such concern could contribute to analytically inappropriate levels of capacity procurement. We also note that public perception of the risk of 'lights going out' has featured strongly in the media in ways that are wholly disproportionate to the actual risk as assessed through successive Capacity Reports.

53. Consequently, the PTE believes there is a public-good case for National Grid to take a more pro-active stance towards public information, to explain in a simple and transparent way the choices and trade-offs involved. Finally, while we applaud National Grid's efforts in promoting DSR via its Power Responsive initiative, we note the wider public and to some extent industry misunderstanding or poor reporting of the potential for DSR.

54. There is a parallel for communication programmes bringing considerable benefits in some countries where there is a high level of meter fraud and non-payment of bills and also where regulators and governments have wanted to remove long standing electricity subsidies. In these countries, as in GB, the target communities are print and broadcast media, business and NGOs and the political establishment. With such communities better informed, there would be less pressure on policy makers to over procure.

New Recommendation 30. National Grid should consider taking a more pro-active role in informing the public about the issues in maintaining security of electricity supply, including the nature of risk and probability, and associated trade-offs. Perhaps this could be co-ordinated through the Energy Networks Association (ENA) or code group with support from Energy UK and Association of Distributed Energy (ADE).

1.4 Electricity demand

55. The electricity demand sensitivities which are applied to ACS peak demand are plus and minus 2% of the Base case. We have commented on demand issues in the previous section and its recommendations. To this we add the need to be clear and consistent in clarifying when demand data refers to transmission-level demand (which has been declining), or the end-user demand (which it appears has been more stable), the difference being attributable to the rise of 'embedded generation' on local networks below the level of the Grid Supply Points – hence also our recommendation above relating to improving data availability on all embedded generation.

1.5 Non-delivery

56. As in last year's ECR non-delivery risks are dominated by the big coal stations, however this year three additional risks have become more salient, namely embedded generation plant, unproven DSR and energy limited technologies, like batteries.
57. Non-delivery of coal plant remains a significant risk of a similar magnitude as last year despite a significant reduction in installed capacity since last year. Coal plant finances are under pressure from low 'clean-dark' price spreads in the day ahead markets and the continuing squeeze on running hours, which means coal plant can now only really count on part time winter operation. Operating at the margin like this increases unit costs and increases risks of outages.
58. The National Grid advice is based on a risk of 4GW non-delivery. This is again due mainly to an assessed possibility of closure of coal plant with CM contracts (assessed as 3-3.3 GW), and non-delivery of embedded generators (0.8-1.2GW) in the light of the charging changes, plus some smaller elements.
59. This was an evolving area of analysis. We agreed that National Grid would model overall non-delivery sensitivities over a range including 4GW, the latter forming the basis of their proposed recommendations. Subsequent to this and recognising that, given the LWR methodology, the non-delivery sensitivity would largely drive the result, the PTE continued to consider the issue. Analysis evolved and we concluded that we do not agree with the logic of simply adding up different potential

areas of non-delivery, since at worse these could be considered independent rather than simply additive.[9]

60. NG has pointed to a number of significant uncertainties relating to a high risk of non-delivery from certain coal plant, embedded generation and unproven DSR in particular, that is not accounted for in derating factors or declared positions. However as non-delivery becomes apparent, it is likely that incentives for the remaining sources of capacity will change; non-delivery of one type would increase the market incentives for others to remain, as a tightening system would increase the value of keeping capacity on the system. If this dynamic is better understood, uncertainty surrounding the net levels of likely non-delivery can be improved.

New Recommendation 31. NG should advance analysis to estimate how, in the event of non-delivery (closures leading to cancellation of capacity contracts) by one source of capacity, the incentives and probability of delivery would change in relation to other sources.

61. These considerations emphasise that the total non-delivery sensitivity should not be the sum of components. In addition, our consultations with embedded generators and with Ofgem led us to the view that non-delivery of embedded generators (due to the imposition of TNUoS charges following Ofgem's decision on this) may be less than we and National Grid initially feared. This is partly because this new cost may be offset by: the optionality values of small scale, transportable and reusable peaking facilities; the potentially higher, more volatile balancing prices expected due to raising of the price cap in the balancing mechanism; and the increasing needs of DNOs for flexible services that embedded generators can offer (the extent to which these values can and will be remunerated remains unclear at present).

62. Consequently, we came to the view that **a 3.6GW maximum sensitivity of combined non-delivery** would be more appropriate. There was also a technical debate[10] about whether this change on its own would imply 50.1 or 49.9 GW procurement, and ways in which the calculations on procurement have somewhat 'rounded up' the total.

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[9] For example, we noted that *if* the components were treated as independent statistical variations, this would result in a sum-of-squares addition, which would yield a total of around 3.6GW from the component numbers – the total being dominated by coal.

[10] Even though all the FES scenarios and all Base Case sensitivities are used to compute a set of worst regret procurements, if the least value in this set happens to be a FES scenario, NG disregard it in favour of the next highest sensitivity. NG argue that they need to procure against a particular Base Case sensitivity. In this case, that reasoning leads to 50.1GW. PTE question this argument and debated that if the minimum of the set is associated with a FES scenario it could be a valid LWR point and in this case, it turns out to be at 49.9GW

63. **This forms the second of the two principal reasons why we believe that the Security Standard can be reasonably met with a level of procurement somewhat lower than that suggested by National Grid.**

1.6 Over delivery

64. This sensitivity reflects the possibility that there may be more non-CM contracted capacity available and interconnectors may import more than their contracted CM capacity. This is to provide balance to the non-delivery, although there is a clear and justifiable asymmetry in the magnitude of the uncertainty, with this upside being just a third of the downside.

Other Sensitivities Considered and Dismissed

65. National Grid has provided good reasons for not considering other specified sensitivities which we have discussed in detail and support for the same reasons.

Dependence of generating units

66. NG treats unplanned outages at multi-unit stations as being independent. Our view is that this is reasonable as it is comparatively rare for two or more units at a station to experience unplanned outages as units are normally designed to run independently and where infrastructure is shared there is normally a degree of redundancy.

Renewable plant non-delivery

67. Initially NG had intended to consider a sensitivity on non-delivery of non-CM plant (it mentions renewables, but it could be nuclear), however it was agreed that the four FES already included sufficient variation in such capacity, so this was excluded.

Black Swan events

68. The extreme outlier events, which tend to be the result of a combination of two or more already low probability events were excluded based on their low probabilities, inclusion of which would distort the LWR results. We discuss this further in Annex 3.

CMU misalignment to TEC

69. The original rationale for this sensitivity was to correct for the excess of offered capacity over the TEC (transmission export capacity) offered by CM participants, however NG has corrected for this in its modelling by capping capacities at TEC levels, so negating the need for this sensitivity. Concerns about a possible 1-1.5GW

'Capacity Gap' of Capacity Market bids in relation to TEC levels have been addressed in rule modifications by Ofgem[11].

Combined sensitivities

70. Almost by definition these combined events would have low probability, comparable to “black swan” events, therefore according to NG’s academic advisors such events should be not included in the LWR approached applied to determine capacity procurement. The PTE accepts this as a plausible approach; however, National Grid could consider historical analysis of the extent to which stress events on its network have been due to combined events and whether such combinations might arise again.

New Recommendation 32. In due course, National Grid should undertake a historical analysis to determine the extent to which stress events on its network have been due to combined events and the assess whether such combinations might arise again.

15-year horizon

71. The ECR includes a 15-year projection of CM eligible capacity for the four FES. The charts (Figure 15, p.39) show the capacity requirement is broadly stable or declining, with the decline being especially marked from the late 2020s. This trend considers commissioning of new CfD-supported capacity (renewables and nuclear), the expiring of existing CfD-supported generation (such as biomass in 2027) and the different demand outlooks.

72. It is interesting to note that NG comments that there could in principle be a risk that plant awarded 15-year contracts in a T-4 auction may become stranded assets, should the demand for this capacity decline markedly in future. This raises a question which is not alluded to in the ECR at all, which is the permanence of the demand for capacity beyond the T-4 delivery year. In a more formal single buyer market model, the procurement authority would select plant based on the output of a formal least cost expansion planning exercise.

[11] https://www.ofgem.gov.uk/system/files/docs/2017/03/statutory_consultation_on_amendments_to_the_capacity_market_rules_2014_final_23032017_0.pdf , Ofgem are addressing this particular problem in Annex F p.56.

Leaving the European Union

Box 1: Extract from PTE 2016 report: Possible implications of Brexit

Last year's PTE report was published in the immediate aftermath of the UK Referendum on leaving the European Union. We included a "**Supplementary Statement by the Panel of Technical Experts on the impact of the EU referendum as follows**

1. *The Electricity Capacity Report prepared by National Grid and the Report of the Panel of Technical Experts were both written prior to the result of the referendum regarding whether the United Kingdom should remain in or leave the European Union (EU).*
2. *The outcome of the referendum may or may not impact the evolution of the electricity markets in a number of ways and it is not the role of the Panel to speculate as to what these might be.*
3. *Nevertheless, the Panel takes a preliminary view that the analyses and recommendations in both these reports remain valid and reliable for the following principal reasons:*
   a. *First, the goal of the reports is to recommend the amount of electricity capacity required, regardless of how capacity is provided, to meet the Security Standard. This is largely separable from the economic circumstances that might affect the outcome of an auction.*
   b. *Second, although some assumptions in the analyses may be affected (such as electricity demand, fuel prices, interconnector development etc.), the analyses are based on scenarios spanning a wide range of economic circumstances. These scenarios are not assigned probabilities because they are differentiated by factors that are hard or impossible to predict or agree upon (such as the result of a referendum). Provided BREXIT the outcomes from leaving the EU fall within these ranges, there would be no reason to reconsider the analysis.*
   c. *Third, the capacity market is structured to allow for existing and new capacity to be committed at the T-4 stage and then for finer tuning at the T-1 stage. These are additional to the balancing services developed and successfully deployed by National Grid along with its 'Power Responsive' initiative. These flexibilities allow for considerable short term adjustments to be made as capacity requirements become more certain with the elapse of time.*
   d. *Finally, there is no suggestion of, or obvious reasons for departing from the goals of the EU single electricity market and electricity interdependence with the EU via interconnection, which together provide a robust framework for co-operation in order to derive very significant benefit for the EU and the UK.*

Whilst the Panel recommends actively monitoring the potential impact of leaving the EU on electricity supply security, at this moment we see no urgent reason to update our report."

73. Since our report of 2016 (see Box 1) there is little more clarity on what leaving the EU may actually mean for the electricity sector. Different possible views on economic growth rates are already accounted for in the range analysed by National Grid in their FES modelling, though this does not affect their Base Case from which procurement volumes are assessed. We remain of the view that the mutual benefits of electricity trade are so large (particularly for GB, where there is no physical possibility to trade with regions outside the Single Market) that trade will continue. It

will be particularly valuable if interconnector arrangements can continue to move forward to maximise the security benefits, including from intra-day trading and agreed measures on mutual response of interconnector flows in the event of stress conditions.

De-Rating Factors (DRF) for Interconnectors

Interconnector De-Rating Factors for T-4 auction procurement (2021/22)

Overview

74. De-rating factor (DRF) ranges for all existing and potential interconnected countries for 2021/22 are presented in Table 1 (for 2018/19 interconnectors are excluded from participating in the auctions for that delivery year). For the range indicated by National Grid, analysis by Pöyry of seven historical years was used to assess the bottom of the ranges (apart from Norway and Ireland), while the maximum values were derived from pan-European modelling carried out by National Grid using Bid3 model.

75. PTE has been asked by BEIS to recommend specific DRF for the power available to GB interconnectors at times of GB need, taking account of ranges proposed by National Grid. These are presented in the last column of Table 1 below. In this section, we comment on the methodologies used to estimate the range, and explain the rationale for the values we propose.

***Table 1**: DRF for Interconnections –*
Range proposed in the NG 2017 ECR and value proposed by PTE

<table>
<tr><th>Interconnection</th><th>Range proposed in NG 2017 ECR</th><th>Value proposed by PTE</th></tr>
<tr><td>France</td><td>48-80%</td><td>70%</td></tr>
<tr><td>Netherlands</td><td>75-81%</td><td>78%</td></tr>
<tr><td>Belgium</td><td>65-85%</td><td>77%</td></tr>
<tr><td>Northern Ireland - Moyle</td><td rowspan="2">Combined:

29-98%</td><td>90% (of 80MW TEC[12])</td></tr>
<tr><td>Republic of Ireland - EWIC</td><td>60%</td></tr>
<tr><td>Norway</td><td>92-99%</td><td>92%</td></tr>
</table>

Overview of the methodology for determining the Derating Factor (DRF) ranges

76. *Minimum DRF for interconnection*

Pöyry carried out the analysis of historical prices and flows to determine the minimum DRF, following the established concept. The historical data used the top 50% of peak demand periods during the winter quarter, 7am to 7pm business days in the last 7 years. For the existing interconnectors with adequate historical data, the average de-rating factors are calculated for those periods where the price differential was positive and the interconnector was importing to GB. These historical de-rating factors set the floor of the DRF range. However, for interconnections with Ireland and Norway, the minimum is based on Bid3 pan-European market model, as explained in more detail for these cases.

77. *Maximum DRFs for interconnectors*

National Grid carried out pan-European market modelling using the Bid3 model that, based on short-run marginal costs and historical weather patterns,

[12] Moyle's current TEC to GB is 295MW, but this is scheduled to fall to 80MW in November 2017.

determines hourly flows between GB and connected countries for each scenario. Flows across the interconnectors are modelled for each scenario based on FES 2017 demand and generation data and electricity interconnector capacities for GB combined with only a single scenario for other EU countries. The maximum DRF was then set by averaging the maximum values across the Base Case and FES scenarios, along with some further 'stress testing'[13]

78. The approach for assessing DRF involves quantification of interconnector flows during stress periods when the GB capacity margin (excluding interconnector flows), is less than or equal to 500 MW. The average flow as a percentage of capacity was then calculated for each connected country and FES scenario. The average value across the four FES scenarios and the Base Case sets the top of the recommended range of de-rating factors. Furthermore, an additional set of de-rating factors was calculated considering interconnection flows during winter weekday evenings (from 16:00-20:00 during working days, from November to February)

79. PTE welcomed enhancement of the analysis as the number of periods considered significantly increased, now covering 29 years, and hence capturing extreme weather across Europe giving greater confidence in the ability of interconnectors to contribute to security of supply in GB when needed.

France:

80. *(a) Minimum DRF*: In 2016, due to low nuclear generation availability in France during the winter quarter, the electricity prices were higher relative to GB during most of the relevant periods resulting in a very low minimum DRF of 25% in 2016, which is in stark contrast to 2015, when the equivalent calculation yields 79%; the 7-year average was 48%. Also in late November 2016, 4 out of 8 cables of the GB-France interconnector were damaged by a ship's anchor during a storm and the interconnector capacity was reduced by 50% for most of the winter period. However, this did not affect the calculated historical DRFs as the absolute volume or level of flow through the interconnector is not part of the DRF calculation methodology, which is a potential weakness of the adopted approach.

81. (b) *Maximum DRF:* the derived maximum (averaged across the scenarios) was 80%. We note that sensitivities with higher peak GB demand, that coincides with French demand peaks that are very temperature sensitive, demonstrated a significant reduction in DRF to a similar level to the historical value.

[13] Further stress testing analysis was carried with demand increased by 5% to examine the impact of the tighter margins on the interconnection flows and the robustness of the DRF in core FES scenarios. Finally, given the very significant capacity margin in Ireland, sensitivity studies were carried out with demand and generation adjusted to bring margins closer to 8 hour LOLE, which is, at present, security target in Ireland.

82. Given the limitation of the approach used for quantifying Minimum value of DRF and the internal analysis carried out, PTE recommends a DRF of 70%. We considered that lower bound was heavily distorted by recent conditions of both the extended interruption of an interconnector broken by a ship's anchor (technical availability is separately accounted) and the closure of French nuclear power stations for safety checks, which drove up power prices in France. This is not appropriate indication of the statistical availability of power to flow from France to the GB in times of GB needs four years from now; aside from its own generating capacity, France is strongly interconnected and could feed power through from other regions if the GB price were high enough. Hence we placed greater weight on the figures obtained from the scarcity modelling.

Netherlands:

83. *Minimum DRF*: Electricity prices in the Netherlands have been generally lower than GB prices during the relevant periods, though in 2016, the reduced regional capacity margins (due to lower availability of the French Nuclear fleet) also affected the electricity prices in the Netherlands electricity market. However, this effect was lower than in countries directly connected to France. The number of periods during which GB prices were higher than the Dutch prices were reduced, resulting in a drop in the 2016 minimum DRF from 89% to 64%. The updated 7-year average DRF for the BritNed interconnector is 75%.
84. *Maximum DRF:* The average of the model-based DRF derived across the Base Case and FES scenarios was 81%. The core modelling assumed capacity of interconnection of 1 GW and PTE welcomed that National Grid considered increasing capacity to 1.2GW for short periods of time during peak conditions. It is interesting that in both cases similar values for DRF were obtained (given that the flows during scarcity were mostly either at maximum imports or zero).
85. PTE recommends DRF of 78%, the mid-point of the narrow range between Minimum and Maximum DRF values.

Belgium:

86. *Minimum DRF:* Given reduced availability of nuclear fleet in France in 2016, regional capacity margins and increased number of high price periods (relative to GB) in the region than in previous years, has resulted in significantly lower imports to GB. This reduced the 'minimum DRF' of the GB- Belgium interconnector in 2016 to 31%, from 87% the previous year, yielding a 7-year average at 65%.
87. *Maximum DRF:* The upper bound at 85% is the average of the FES scenarios. Despite having a very different capacity margin in Belgium compared to Netherlands and France, all three interconnectors have similar patterns to the de-rating factors in the modelling, as regional rather than country-specific capacity margins tend to drive interconnector flows.

88. PTE proposed that DRF for Belgium interconnector should retain last year's value of 77% which is also near the middle of the National Grid range (making it a fraction below Netherlands, given that Belgium is characterised by tighter generating margins)

Ireland:

89. *Minimum DRF:* Given that the price differentials narrowed between GB and Ireland in the latest three years, the analysis carried out by Pöyry has resulted in an increase in the number of positive price differential periods during the relevant periods. However, this still resulted in low DRF of 13%, indicating ongoing inconsistent behaviour of these interconnectors in the context of the approach used for determining DRF. Therefore, PTE supports National Grid assumption that by 2021/22 there would have been several years of market coupling, in which case the Pöyry history would no longer be relevant for setting the low level of the DRF. Furthermore, this included assumptions of growth in electricity demand presented by Eirgrid combined with the expected reduction of generation capacity margins (in line with Irish capacity market target of 8 hours LOLE). Overall, this increased the minimum DRF to 29%.
90. *Maximum DRF:* Simulations of FES scenarios carried out by National Grid used Irish demand and generation forecasts that are consistent with ENTSOE figures. This gave a large surplus of generation over demand enabling Ireland to provide very high exports at times of low GB margins. Current limits between the north and south are assumed to be rectified with an additional North/South link, which is anticipated to be operational before 2021/22. This resulted in the maximum DRF of 98% for Ireland interconnection. It is important to bear in mind that this DRF applies to very constrained Moyle interconnection (due to constraints within Scotland import capacity which will limit capacity to 80MW from November 2017).
91. PTE also points out that the analysis of DRF for Ireland is complicated by on-going technical problems with both Irish East-West and Moyle interconnectors as the capacity to which the DRF applies is changing. In September 2016, the Irish East-West interconnector had a fault that occurred during an annual maintenance at the converter station in Meath. The interconnector re-entered service in December 2016 with a fully rated 500 MW import to Ireland, however imports to GB were limited. Similarly, operational problem arose with the Moyle Interconnector in February 2017.
92. Many other factors differentiate the two interconnectors from GB to Ireland, including onshore transmission constraints on each side, and very different historical patterns of technical performance and failure. Differences could even be amplified after Brexit, as Moyle connects to Northern Ireland and EWIC to the Republic of Ireland. Consequently, PTE considers that DRFs for the Irish East-West interconnector and Moyle interconnector should be presented separately.

93. Though Ireland has higher power prices (which historically have attracted exports *from* GB), this is not relevant to behaviour should the GB system be in need of power, with high wholesale prices; the modelling results with high DRF consequently reflect the fact that Ireland has a large surplus generating capacity and is expected to continue to have larger margins than GB even after closures. This explains the huge range between minimum and maximum DRFs in the National Grid methodology.
94. On balance, we recommend a DRF of 60% for EWIC. The DRF for Moyle will be dominated by the assumed capacity to import into the main GB system as constrained by local capacity. We would expect a very high DRF – at least 90% - *relative to the published TEC (transmission export capacity[14]) constraint of only 80MW* (which is far lower than the interconnector capacity itself).

Norway:

95. Minimum DRF: In the analysis carried out by Pöyry, DRF of GB-Norway interconnector remained very high as hydro based historical electricity prices in Norway during the relevant system stress periods in GB remain lower than the GB prices.[15] In the final analysis, the DRF for Norway was set by the Bid3 analysis of FES scenarios and the lower bound from the Two Degree 5% demand increase stress test (given that Norway has interconnectors with several countries).
96. Maximum DRF: The proposed maximum was set at 99% as the average of the Two Degrees scenario.
97. The PTE recommendation is 92%, at the lower point of this range (but still the highest of all the interconnectors), reflecting that historical data may underestimate the possibility of extended drought affecting Norwegian hydro availability.

Summary on Interconnectors

98. In the context of the analysis framework for assessing the contribution of interconnectors, PTE supported the analysis carried out for determining derating factors for interconnections. Furthermore, PTE welcomed enhancement of the analysis covering 29 years and hence capturing extreme weather across Europe giving greater confidence in the ability of interconnectors to contribute to security of supply in GB when needed. On the whole, PTE agrees that the ranges of DRFs identified by National Grid are credible and has been asked to comment on the possible choice of de-rating factors, and the arguments for taking higher or lower

[14] Interconnector capacities are listed separately in the Interconnector Register

[15] After a drop in DRF in 2015, driven by several unusual cold spells in Norway (85%), the DRF in 2016 increased again to 98% as electricity prices in Norway were predominantly lower than in GB due to warmer winter conditions (average winter temperature in Norway was higher than the seasonal norm during the 2016/17 winter).

values. For reasons of transparency and the possibilities of internal transmission constraints, PTE suggest that the relevant organisations consider the case for estimating DRFs specified for individual interconnectors, rather than countries, and the rule changes that may be required to enable this.

New Recommendation 33. There is a case to estimate interconnector derating factors for individual interconnectors rather than countries; in particular, NG should refine the inclusion and presentation of internal transmission constraints within both GB and the Island of Ireland, so as to facilitate estimation of derating factors for the Moyle and EWIC interconnectors separately in future years.

99. PTE remains concerned with the application of historical approach, as historical prices are not very relevant for scarcity periods when the GB system would be in need of power. In this context, PTE supports the application of the Bid3 model and the National Grid plan to develop a range of EU generation and demand assumptions to complement the GB FES scenarios, although we also recognise that the current CM rules mandate a historical analysis.

100. There remain some outstanding issues for future consideration:

   a. DRFs can only be estimated with respect to an assumed maximum capacity, but as indicated above for several interconnectors, this ‘maximum’ itself appears to be somewhat flexible or subject to interpretation.
   b. As discussed in our report last year (PTE 2016), increasing interconnector capacity from the present level will tend to reduce the de-rating factors (as interconnection capacity increases and the saturation effect begins to manifest). Thus, there will be a growing need to consider the interactions between DRF among interconnectors.
   c. There is uncertainty regarding the market response to stress events, particularly in the context of the interaction between day ahead, intra-day and balancing markets and how interconnectors engage in these markets.
   d. Finally, there remains a level uncertainty in the amount of de-rated capacity that can be delivered by interconnection until TSOs at either end of each interconnector draw up and publish the rules that govern out-of-market actions.

Comments on Target Capacity

The T-1 auction for 2018/19
Volume for T-1 auction procurement for Winter 2018/19.

101. National Grid have recommended procuring **6.3GW,** based on a number of technical adjustments (with which we concur) combined with changes in expected demand and concerns about non-delivery of capacity procured in the first Capacity Market auction. This is far more than the 2.5GW originally set-aside in 2014, albeit less than National Grid indicated last year might be needed, a considerable capacity to procure on a year-ahead basis.
102. Our advice is that the Security of Supply standard could be met with **not more than 6GW**. To summarise the key elements from our discussion above, our rationale is as follows.
103. National Grid's **demand adjustment** reflects in part the accounting complexities arising from previously inadequate data on embedded generation, which had previously appeared as reduced demand on the transmission system. We accept the case made for this adjustment. However, we note that the demand projection does not take account of the potential for demand-side responses to potential scarcity pricing, as discussed. Recognising the limited evidence in this area, we propose only a small adjustment for this at present - but not zero.
104. Concerning non-delivery of plant with capacity contracts, National Grid's analysis has 1.7GW known non-delivery in their base case, augmented with sensitivities up to an additional 2.8GW non-delivery, the latter based on perceived possibilities of an additional 2.2GW coal closure, 0.5GW loss of embedded generation (justified in part due to Ofgem changes concerning charges for embedded generators), and 0.1GW loss of demand-side response compared to contract. We now consider this excessive: with the coal plant already lost, market conditions for remaining coal are not as difficult; Ofgem's changes to embedded benefits are only being phased in and the evidence we have been able to gather subsequently allays some of concerns about the scale of short-run impact. We question whether the different sources of non-delivery should be simply added in this way (discussed further regarding the T-4 auction). Our own analysis confirms that the procured volume would reduce in line changes to the maximum non-delivery (e.g. if it were 2.4 instead of 2.8, then procurement would be 5.9 instead of 6.3).
105. Finally, our analysis of the derating factors for interconnectors for the T-4 auction presented below is towards the higher end of National Grid's assessment, and the same logic would also apply to their assessment of the security value of interconnectors in T-1, where National Grid assess the interconnector capacity as only contributing 2.1GW to security at peak need in 2018/19 based on its application of auction derating factors.
106. That said, 2018/19 is close and the room for major deviations from National Grid's analysis is limited. We consider a prudent approach would be to target a T-1

capacity procurement of no more than 6GW: we believe this would be reasonable even on the sole grounds of our findings regarding non-delivery sensitivities (where a 0.3GW reduction would lead to a reduction close to 0.3GW in procured capacity based on the LWR methodology). It remains even more conservative if considered as an adjustment of at least 0.1 GW for each of the above three points.

The T-4 auction for 2021/22
Volume for T-4 auction procurement for Winter 2021/22.

107. National Grid have concluded that **50.5GW** should be procured in the Winter 2021/22 auction, based on the prescribed methodology. PTE believes that the volume need be no more than **50GW to maintain the security standard**. The main reasons for our lower view relate to the same factors as indicated concerning the T-1 auction, but both are enhanced for 2021/22.

108. Demand response could be enhanced by thee wider use of smart meters and controls and by the raising of the cap on the Reserve Scarcity Price in the Balancing Mechanism, which doubles to £6,000/MWh (April 2018). We reiterate that allowing for companies (and other consumers) saving money, by reducing demand (or increasing self-generation) during brief price spikes, outside of any Capacity Market arrangements, is likely to cost much less than procuring additional and ultimately unnecessary capacity.

109. As discussed, we now conclude that the *total* sensitivity for non-delivery of existing CM contracts could be most reasonably estimated at 3.6GW. The timescale would allow for more market response (e.g. if more coal plant left the system and cancelled contracts, the value of plants remaining would be enhanced) and more adjustment for embedded generators, for example through remuneration of other system services they could provide at local level.

110. Consequently, we believe that the procured volume need be no more than 50GW to reasonably meet the Security Standard. However, should the government wish to keep with the National Grid recommendation of 50.5GW, we believe the government should alternatively consider deferring more of that capacity to the T-1 auction in 2020, by which time these key uncertainties around demand and non-delivery should be much clarified.

Methodology

111. We welcome the forthcoming 5-year review of the Capacity Mechanism. As a contribution towards issues that this might consider, in this year's report, we re-visit two related and persistent themes that are central to the determination of the capacity to secure. These are:
   - *improvements to the Least Worst Regrets methodology,* where we believe that current approaches tend to overstate capacity requirements; and
   - *to aim for a more granular and targeted evaluation of the Value of Lost Load ("VoLL")*, including the potential for some of the Emergency Actions available to National Grid (such as voltage control and maximising generation) to protect consumers from loss of load, which we suggest could be termed "Latent Capacity"

   Annex 3 gives full detail and definitions, which we summarise briefly in this section.

112. Regarding *Least Worst Regrets*, we have previously pointed to a number of technical concerns regarding the implementation of the Least Worst Regrets methodology. Both scenarios and sensitivities are treated as equally likely. In cases where, for example, a sensitivity of an outcome (such as the most extreme weather conditions) that is known from data to be statistically highly improbable, is given equal weighting with all other sensitivities, the result of the Least Worst Regret calculation is clearly distorted in the direction of over-estimating capacity requirements. National Grid's academic advisors have carried out important new work in creating a methodology which would allow for this, although it needs more refinement and testing before use.

New Recommendation 34: We welcome the response from National Grid in addressing last year's recommendation to consider the application of weightings to Least-Worst Regrets assessment (Recommendation 25) which concluded that extreme events should be assigned low weights or excluded. However, we believe there is merit in considering further how best to treat less extreme events, for example, through weighting sensitivities (as outlined in last year's PTE 2016 report, p43) and the insights this can yield.

113. When a system stress event is anticipated or in progress, various measures are potentially available to the System Operator and Distribution system operators. As well as various currently classed as 'emergency actions', these can include for example, reducing demand on the system by reducing voltage (an example we

particularly cite here because it is, in principle, controllable)[16]. The Reliability Standard or 3 hours' loss of load expectation over a long period) is measured prior to such actions, whereas the Value of Lost Load is assessed after such actions. This mismatch has the effect of adding a proportion of the controllable measures to the capacity to secure. We believe that further consideration should be given to whether and how such potential "Latent Capacity" should accounted for in the capacity assessment process.

New Recommendation 35: We are keen that National Grid consider again our previous Recommendation 16 but broadened to include consideration of the range of additional forms of 'latent capacity' (such as various possible responses of DNOs to demand reduction requests).

[16] See the box in Annex 3 on the experience of CLASS voltage control.

Quality Assurance

114. Previously followed procedures continue to provide QA. These are closely aligned with BEIS's internal QA processes.
115. Compared to previous ECRs additional checks have been introduced for the implementation of modelling extensions introduced in the 2016 ECR. These checks are related to the new methodological approach for the analysis historic demand and embedded wind, which produces a demand distribution to be included in the DDM. An additional check is also associated with the CM results included in the DDM input template.
116. The PTE previously requested details of the ECR Quality Assurance methodology, which was reproduced in Annex 2 of PTE's 2016 report.

Annex 1 - Progress on the PTE's Previous Recommendations

117. Last year's (2016) PTE report made 10 new recommendations, numbered from 16 to 25 (continuing on from the previous years' numbering). All these recommendations, along with others raised by BEIS, Ofgem and National Grid's internal post review/update process were considered in the project evaluation, whereby all recommendations received by National Grid are scored by National Grid, BEIS and Ofgem according to their impact, priority, and effort – see ECR 2017 Annex 4 (table 26). In the end, the resources available to National Grid allowed five of these proposals and a previous one (Recommendation 13 covering development of a pan-European model to address European interconnector derating factors). The five addressed recommendations from last year were:
    - No. 22 – improving demand forecasts via analysis of data on small scale generators and DSR;
    - No. 25 – review overall modelling approach to consider application of probabilities or weighting to less likely sensitivities;
    - No. 24 – analysis of magnitude of VoLL and risk around reliability standards – which NG has passed on the BEIS/Ofgem to lead (with National Grid support) as it is part of a wider forthcoming CM review;
    - No. 17 – ways of accounting for probability of contracted CM parties fulfilling their contract;
    - No. 21 – analysis of impact of policy changes/risks on non-delivery risks (which ended up focusing on the change in embedded benefit arrangements for distributed generation and storage assets.
118. The PTE is pleased that National Grid has addressed these issues. We wish to draw attention, however, to two previous recommendations that are key and remain to be addressed, specifically: Recommendation 23 (market response under tight conditions); and Recommendation 16 (potential DNO responses to Demand Control orders). Recommendation 23 requested National Grid to make more efforts to understand the impacts of scarcity pricing on demand, while Recommendation 16 sought more information about the actual or potential options for Distribution Network Operators to respond to requests by the System Operator, for example through CLASS voltage reductions (as discussed further in Annex 3 below).
119. We also consider, on reflection, that Recommendation 25 (which considered the application of probabilities to sensitivities) has not been fully closed out. National Grid's academic advisors (Wilson and Zachary) demonstrated that applying low probabilities to extreme outlier sensitivities would not significantly influence the results. There is, however, a distinction between assigning probabilities to extreme

possibilities outside the range considered in the sensitivities, and applying lower weights to the "extremes" of the ranges considered. Our sensitivity test last year which applied differential (albeit judgemental) weights to the extremes of CM non-delivery (included in our 2016 report) still merits further interrogation. We have therefore updated and clarified this further as our New Recommendation 34 in this current report.

120. We note that previous Recommendation 17 (assessing the probability of non-delivery of CM capacity) was only partially addressed as it was bundled with Recommendation 25. We recognise that quantification of such plant-specific probabilities is arbitrary, and that any changes to the selected sensitivities are unlikely to provide significant additional insights, so we remain content in this regard.

121. Similarly, Recommendations 18 and 19 were not addressed. Recommendation 18 had concerned investigation into the impacts of other extreme weather conditions (humidity, air pressure and precipitation, etc), and Recommendation 19 concerned the benchmarking of GB availabilities versus international experience. We are content to see these lapse for now as other more urgent and important matters have arisen and are being addressed.

Annex 2: Distributed Energy Resources - data availability, quality, and issues affecting derating factors

122. A major change in our electricity system in recent years has been the growing scale and significance of ‘distributed energy resources’ – generation, responsive demand, and storage – connected at the distribution level, below the level of the Grid Supply Points which constitute demand on the national transmission system.
123. This is raising multiple issues for capacity assessment. Such distribution-level generation and storage (“Embedded generation”) can contrast greatly with the conventional pattern of large scale generation feeding through the transmission system down to distribution network operators (DNOs). This Annex focuses on two main issues raised by the different nature of these resources: the quality of detailed data available to assess the implication of these trends for overall capacity needs; and the implications for approaches to derating such distributed energy resources, as and when they seek to participate in the Capacity Mechanism.

Availability and quality of data

124. In PTE 2016, we expressed concern about the inadequacy of data available concerning such ‘Embedded generation’ (and other Distributed Energy Resources). Such data are relevant both to understanding trends in actual final (“underlying”) demand (as opposed to that visible from the transmission system), and for estimating the actual performance of, and hence derating factors for, embedded generators which form an increasing percentage of capacity bidding in to the Capacity Mechanism.
125. In this year’s National Grid ECR (Electricity Capacity Report), p17, the relevant section is:
    - *Process to improve both demand forecasting and CM de-rating factors for distribution connected generation technologies by acquiring and utilising distribution generator and Demand Side Response (DSR) data (PTE recommendation 22). This project was progressed by contacting Distribution Network Operators (DNOs) and ElectraLink (the company that manages half-hourly data for DNOs in England & Wales via its Data Transfer Service) from whom we purchased 4 years of historical anonymised output data aggregated by technology and Grid Supply Point (GSP) substation. While the output data proved useful, there were some quality issues encountered through the matching process used to estimate the aggregate capacities by technology*

and GSP. Where issues were observed in the aggregate capacity data, it was not possible to filter out individual sites since the data provided to us was aggregated. Consequently, we were only able to make enhancements for some technologies but they were limited for both demand forecasting purposes and de-rating purposes with the latter also being prevented for CM technologies as the proposed rule change (CP191) that would allow it was rejected by Ofgem. Overall there was some improvement but potentially if the data quality issues can be sorted and an acceptable rule change can be agreed then this source of data (the only substantive one for distributed generators) could be instrumental in improving the modelling going forward.

126. This was the result of work packages EMR7 to improve demand forecasting and EMR16 to update de-rating factors, which highlighted that:
    - The National Grid's demand forecast accuracy incentive is measured against national demand as measured at Transmission (GSP) level, whereas the Base Case expectation and FES scenarios take a view of underlying demand, i.e. gross demand without embedded generation being netted out.
    - For de-rating factors on embedded generators, the rule has been that the 'closest' (most similar) transmission connected technology should be used as basis for assessment. Alternative approaches have so far proved difficult.[17]

127. The data quality issues relate to:
    - Various apparent inconsistencies, as indicated by National Grid, for example unexplained jumps in the reported output, unrelated to (sometimes much above, sometimes well below) the reported capacity
    - The basic unit of metered data ("MPANs", Meter Point Administration Number) does not identify technology nor the installed capacity, just consumption or production. ElectraLink do some Fuzzy Matching from various public registries to infer these and thereby create load factors. They claim 90% of output matched to technology and 80% match to capacity. Nevertheless, a large number of heuristics (approximation techniques) were required to estimate credible load factors.

[17] NGET proposed a CM rule change (CP191) which would have sought to use output data to estimate derating factors, but this was rejected by Ofgem based on the fact that calculating de-rating factors with output data is not consistent with the intent of the de-rating process, which aims to capture availability. Moreover, this issue was further aggravated by the limitations to the quality of the data that have been highlighted by NGET. ("Decision on further amendments to the Capacity Market Rules, Ofgem" (undated), concluding an Ofgem consultation from 25 March to 5 May 2017. https://www.ofgem.gov.uk/system/files/docs/2017/06/20170628_cm_rules_decision_final.pdf). In a recent decision on further amendments to the CM rules, it was made clear that Ofgem would be supportive of a change which would improve the accuracy of the de-rating methodology and that Ofgem is happy to work with NGET if they submit a further proposal (pages 6-7).

128. Given these data quality issues, we offered the view that the ElectraLink data could not reasonably be used to estimate derating factors for embedded generators in this year's ECR, but that high priority should be given to improving data for future years[18].

Impact of Balancing and Settlement Code Modifications

129. Ofgem have ruled that embedded generation will have to start paying Transmission Use of System (TNUoS) charges. This means that National Grid need to have access to gross Balancing Mechanism (BM) unit data from such generation. Two modifications to industry codes (Balancing Settlement Codes, developed by the industry's CUSC panel) – BSC Modifications P348 and P349 - have made that possible from February 2018. Ofgem's decision on these Modifications[19] states that:

> *"This modification is a simplified SVAA option where National Grid is only sent gross half hourly (HH) embedded export and gross HH demand associated with the individual Supplier Balancing Mechanism Units.*
> *The data for this can be calculated from existing settlement data. National Grid will also be provided with three years of historical data."*

130. This will help directly with demand forecasting (EMR7), though the extent to which this and other data sources will also provide adequate data on the capacity and output of "behind the meter" generation is unclear, such as industrial backup generation and rooftop PV. Also, the Code Modifications will still leave the same problem of "fuzzy matching" for the de-rating factors required in EMR17.

131. Overall, we are thus unclear as to how much the BSC code modifications – designed to collect data on embedded generation for the purposes of levying certain TNUoS charges – will resolve our concerns about the adequacy of data for wider understanding of the trends in embedded generation and underlying energy demand, and the estimation of derating factors for embedded generators participating in the Capacity Mechanism. This underlies our New Recommendation 27, that *Improving data and providing access to the best available data on embedded generation (including for National Grid) should be prioritised as a matter of urgency, if possible before next year's ECR.*

[18] The ElectraLink data does not cover all embedded generators e.g. those in Scotland.

[19] "Balancing and Settlement Code (BSC) P348 and P349: 'Provision of gross BM Unit data for TNUoS charging' (P348) and 'Facilitating Embedded Generation Triad Avoidance Standstill' (P349)", Ofgem, 22 June 2017
https://www.elexon.co.uk/wp-content/uploads/2016/07/P348-349-Authority-letter.pdf

Impact of location and scale, and storage tank capacity, on relative derating factors for distributed energy resources

Impact of plant location and scale on de-rating factors

132. Distributed Energy Resources (DERs: embedded generation, energy storage, demand side response) generally involve less line losses in distribution and transmission networks compared to generation connected at transmission level. This is because they act to reduce the net load – in most cases embedded generation would reduce the load that a given DNO calls from the transmission system. This is particularly relevant and important during peak demand periods, when line losses are also at their highest (losses are generally a quadratic function of the power flowing through a line).

133. Current approaches to derating factors do not consider this enhanced contribution of DERs to security of supply. This effect is however taken into account in some other jurisdictions (notably the US, namely ISO New England and PJM), where DERs are "grossed-up" by the avoided peak transmission and distribution network losses, that are estimated at 8%. Recent analysis estimated that network losses in GB may exceed 10% during peak demand condition[20.] At present the de-rating factors of generating plant is influenced only by the type of plant and not by its location, but there is a clear case to be considered to include this contribution to DER, for example though adjusting the de-rating factors accordingly.[21]

134. In addition, systems composed of plants with large unit capacities (e.g. large-scale generation connected to transmission network) require a higher capacity margin than a system supplied by more, smaller plants (such as DER), for the same risk of loss-of-load. This is because – for a given average plant availability - there is a greater risk of a few large plants failing simultaneously, than equivalent capacity comprising far more simultaneous failures of smaller ones.[22] The present approach to derating also does not take this effect into account. PTE has raised this point and

[20] "Management of electricity distribution network losses" Imperial College London, Sohn Associates, report for WPD and UKPN, 2014.

[21] Note that location specific transmission loss factors, for balancing market purposes, will be introduced from April 2018. This should also enable recognition of the actual location of individual generator when quantifying corresponding DRFs for the capacity market purposes (a generator in Scotland will have lower DFR than a generator in England, due to transmission losses).

[22] To illustrate the importance of the plant size when determining the capacity margin, analysis was carried out by Imperial College demonstrating that maintaining the same capacity margin with different plant size would lead to very different LOLEs. For example, a system supplied by generating plants of 500MW rating and 85% availability will require capacity margin of around 10GW to achieve the target LOLE of 3hours. If the same capacity margin is maintained while the plant size is 100MW (with the same availability of 85%), the LOLE would be only 0.1 hours. This is 30 times lower LOLE than prescribed by the standard. This indicates that plant unit size affects the overall contribution to security and hence should influence derating factors.

National Grid indicated that this issue would be considered and that modelling would be updated to take into account plant size.

De-rating factors of energy storage plants

135. There is a significant interest in deployment of energy storage technologies to provide various system services, including participation in the capacity mechanism. At present, the only parameter that drives the security contribution (de-rating factor) is the plant availability. However, for energy storage, the size of the storage tank in relation to the shape of demand peaks will be critical for determining de-rating factors. A range of other significant factors (size, location, and dynamic characteristics etc) may also affect the value of the various storage technologies now being deployed or considered.
136. Hence our New Recommendation 28: *"We recommend that National Grid develop a derating methodology for energy storage that considers the size of the storage tank in relation to derating factors; In addition, National Grid should consider the extent to which Distributed Energy Resources (including embedded generation, energy storage and demand side response) incur lower network losses and the possible implications of this for the estimation of de-rating factors".*

Annex 3: Extreme circumstances, probabilistic approaches and relationship to system stress options (the 'Emergency Actions')

Introduction

137. The purpose of this Annex is to bring attention to various issues relating to the translation of the Reliability Standard into specific recommendations that could bear upon the government's forthcoming reviews. And to explain the links between these issues, for consideration by BEIS, in seeking to improve Capacity Mechanism procurement decisions for future years.
138. Whilst the public, industry and commerce all desire supply security, there is a limit to the cost which consumers are prepared to pay for it, depending on many factors. For example, the operation of a washing machine is not normally as essential as the supply of constant power to a hospital, hence we would expect the former to put less value on supply security than the latter. From an economic and industrial standpoint as well, security of supply is important but so too is the cost of electricity, and again the value of different uses varies.
139. The essential trade-off that is at the heart of calculating the capacity to secure is therefore security of supply as against the cost of securing that supply. This is encapsulated in the government's Reliability Standard. In itself this is beyond the remit of the PTE, and we welcome the government's forthcoming review of the Reliability Standard and associated Value of Lost Load.
140. The Reliability Standard derives from considerations of balance - between the costs of supply risks and the cost of building capacity that may never be needed. The PTE's role concerns the application of these requirements into specific recommendations, particularly in reviewing National Grid's analysis of the implications for capacity, against a background of very wide uncertainty regarding technical assumptions, and using our related expertise to help inform further developments.

Accessing Latent Capacity by Revisiting "Loss of Load" and "Emergency Actions"

141. Contrary to popular perception it is impossible to protect against all circumstances and guarantee continuous nationwide 24-7 electricity supply, due mainly to weather extremes and equipment breakdowns. Protecting against ever more severe (but unlikely) events requires additional investment – costs which are generally paid by all consumers across the system. One of the aims of GB energy policy is to set an appropriate balance between this cost and the risk of blackouts.

142. Based on estimates of the *Value of Lost Load (VoLL[23])*, which represents an informed judgement of the cost of forced disconnections based on estimates gathered in highly structured consumer surveys[24], together with estimates of the cost of new entrants to provide electricity capacity, the government has derived its Reliability Standard[25]. This standard is defined in legislation as follows:

> **"*The Reliability Standard is 3 hours of expected loss of load per capacity year*"[26].**

143. With the assistance of the relevant Regulations, we interpret this as follows:
    - "expected" is interpreted as the statistical concept of "*expectation value*" which means that that *on average* consumers should experience 'loss of load': for *not more than 3 hours a year* when averaged over the long term but always in relation to the period under consideration for a particular capacity auction.
    - "Loss of load", somewhat paraphrased from the Regulations, occurs if one or more of the following happens:
    - the System Operator (National Grid) takes *Emergency Actions*, which in the regulations are in essence:
    - instructions to generators to increase to maximum output ("MAXGEN")

    secure additional imports from interconnectors, in circumstances where such transmission would not otherwise have occurred.

[23] "VoLL represents the value that electricity users attribute to security of electricity supply and the estimates could be used to provide a price signal about the adequate level of security of supply in GB." (London Electricity).

[24] The Value of Lost Load (VoLL) for Electricity in Great Britain, London Economics, July 2013. (The report estimated a large number of VoLLs based on a "choice experiment" whereby consumers were asked the price they would be will to pay to remain connected and the payment they would accept as compensation for disconnection. The outcomes varied widely by sector and by willingness to pay compared with willingness to accept, duration and frequency of outages. For convenience, a single value was adopted.

[25] The derivation of the Reliability Standard can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf

[26] Regulation 6, Part 2 of The Electricity Capacity Regulations 2014, SI 2014 No. 20432 as amended (http://www.legislation.gov.uk/uksi/2014/2043/contents/made).

The System Operator instructs one of more Distribution Network Operations (DNOs) to reduce load, either by

- reducing voltage, or
- selective disconnections
- automatic or low frequency demand disconnections take place.

144. It is clear from the above that: <u>a 'Loss of Load' in the above definition may not imply any involuntary disconnection</u>. The Reliability Standard does not have a simple equivalence to a calculation of the difference between maximum demand and maximum generating capacity. Consequently, supply margins, a concept seemingly favoured in the press, can be a misleading guide to security of supply. For example, if the demand side is engaged and can offer demand reduction at times of forecast system stress, there will be no system stress event even where the supply margin may appear to be negative.[27]

145. The Reliability Standard is neither a maximum nor a minimum threshold, but a target which the system operator is required to secure. If too little capacity is secured, then consumers might not receive supplies that they were willing to pay for and if too much capacity is secured, consumers would be paying more than they would be willing for the additional security of supply.

146. This then characterises the legal basis against which National Grid assess and formally recommend the capacity required to secure in the Capacity Market, which the PTE then independently scrutinises.

147. In our previous reports, the PTE has expressed concerns about the interpretation of VoLL as applied in the 'Least Worst Regret' methodology[28] being used to assess the capacity to secure implied by the Reliability Standard. We have also noted that the Reliability Standard was being defined in terms of the costs of blackouts, but applied to assess the amount of capacity required to avoid conditions of *system stress.*

148. A condition of 'system stress', for this purpose, can be understood as one in which *Emergency Actions* are in progress but *involuntary disconnections have not taken place.* Such a condition might arise if the nameplate generating capacity available is insufficient to meet the 'natural demand' – the amount which consumers would use if sufficient capacity were available and generating in normal market conditions.

[27] For example, during the shutdown of numerous nuclear plants in France in 2016, demand was at times reduced by almost 4GW (on a 70GW peak demand which unlike the UK at present, includes significant electric heating hence a very high reduction) compared to what it might have otherwise have been – but there was no 'system stress' event.

[28] See the Electricity Capacity Report 2017, National Grid, for a comprehensive description of Least Worst Regrets.

149. We are pleased to note that BEIS propose to commission a substantive review of the approach to reassessing the determination and application of Value of Lost Load, as part of the Department's Reliability Standard review.

'Least worst regret', Probabilistic Assessment and Hybrid approaches: the Wilson and Zachary assessment[29]

150. In an uncertain world, the methodology used to assess the capacity required to meet the Reliability Standard is known as 'Least Worst Regret', as described in this and National Grid's reports in this and previous years. "Regret" is calculated as the difference between the maximum and minimum outturns (payoffs in game theory terms) for a particular procurement option under a range of scenarios / sensitivities. The procurement option that minimises these regret values is the "Least Worst Regret" option. The analysis for National Grid by Wilson and Zachary formalises the concerns we have previous expressed about the LWR methodology, noting:

- *"The above [example] represents the major weakness of LWR analysis. The two scenarios or sensitivities i_l and i_u which essentially drive the result of the analysis are often, as in the example above, relatively minor ones. Yet the necessarily subjective decision on the scenarios and sensitivities to be included in the analysis is critical in determining its result.*
- *… [Moreover] that it is the most pessimistic or optimistic scenario or sensitivity which mainly determines the result of the LWR analysis."*

151. Their report clarifies the mathematics of probabilistic approaches to electricity security of supply assessments, and offers examples applied to the GB system, but they also identify major drawbacks, which we fully acknowledge.[30]

152. They did however suggest a hybrid approach, in which the present LWR methodology is supplemented by a probabilistic approach to factors which might be considered "plausible but very unlikely", and hence not within the main set of scenarios and sensitivities. PTE noted a certain paradox in this approach, in that it requires probabilities to be assigned to scenarios/sensitivities which are considered *very unlikely* – and hence for which there may be the least empirical insight available from past history.

[29] See https://arxiv.org/pdf/1608.00891.pdf

[30] Wilson and Zachary conclude that fully probabilistic approaches would (a) greatly increase workload because every scenario/sensitivity combination would have to be assigned a probability and correlations would need to be assigned to ensure only self-consistent outcomes are analysed, (b) reduce transparency of the analysis because of this vastly increased complexity and (c) most fundamentally cannot in practice get around the fact that, at the end of the day, such assessments would remain ultimately subjective: the subjectivity would be transferred to estimating probabilities of different conditions, rather than the choice of the most extreme ones.

153. One source of risk of course is what has become known as ''black swans" – events (sometimes, the convergence of multiple events) which could hardly be conceived before they happened – in which case, assigning them probabilities is a somewhat false exercise. For example, the GB system could obviously be at severe risk of blackouts *if* there were a sustained interruption to gas supplies, but GB has a relatively diverse mix of gas supplies and strong infrastructure, and BEIS indicated that this is not considered a source of concern. It is hard to conceive how this could happen and therefore somewhat arbitrary to assign probabilities, other than "very low".

154. Nevertheless, we were grateful that National Grid did conduct a trial run to assess the impact of adopting such a hybrid approach. Broadly the conclusions were that adding this hybrid component would be unlikely to make much difference to the capacity procurement decision. This is because although such extreme circumstances might generate high costs, factoring in their low estimated probability largely negates their impact on the final result. And if the probability of extremes is assessed to be higher – then they should be moved into the core set of the LWR analysis.

155. In last year's (2016) report (p43), we considered a different approach, which showed that applying decreasing weights for more extreme sensitivities *within the LWR set of sensitivities* (in our example, CM non-delivery sensitivities) could have a substantial impact on LWR results. Our view is that this analysis has not been refuted, although we acknowledge that there are issues regarding the selection of weights, but this is a challenge that other policy makers using Multi-criteria analysis have become comfortable with. Consequently, our New Recommendation 32 that this remains an area for further exploration.

"Value of Lost Load" and "Loss of Load Expectation"

156. The risk of *not* having any targeted approach to considering 'possible but very unlikely' events is the temptation to include as wide a range as conceivable in the LWR analysis. This, in turn, risks driving up costs to consumers to unnecessary degrees. The institutions concerned are naturally keen to minimise *any* identifiable risk of blackout (and to be seen to do so), which may inadvertently lead to economically unreasonable costs of procuring excessive capacity. BEIS relies on PTE to identify any such tendency.

157. Rather, and given the conclusions of the Wilson and Zachary analysis, we suggest that the issue of whether and how to account for extreme 'possible but very unlikely' events should be considered alongside another observation expressed in previous PTE reports, namely that in fact, conditions of generating shortfall do not, as usually assumed, necessarily lead to blackouts.

158. The 'loss of load expectation' (LOLE) – the formal measure of the expected hours of 'loss of load' as defined above in detail - is in fact misnamed because it does not

measure loss of load in most circumstances of ‘system stress’. A measure that combines average loss of load duration with the depth of the stress event (eg. energy unserved) might provide a more meaningful measure of impact. (Imperial College has done extensive analysis on this as we noted in our report last year).

159. As the system approaches such conditions, a multitude of options could be made available. Just a few examples, some of which are already available in the current market, include:
    - Demand-side response: consumers can offer to reduce demand in response to generation shortfalls.
    - Fast and Enhanced Frequency Response: through a variety of technologies such as electricity storage and voltage control.
    - Industrial backup generation, which for one reason or another does not participate in the capacity market but which could (even if not able to feed into the grid) displace some business loads on the system
    - Load differentiation: developing a wider ability within the system to prioritise essential loads (such as hospitals, airports and world cup finals on TV) over non-essential loads (such as non-urgent washing machine cycles, supply to domestic fridges) could enable different values of lost load to be assigned depending on priority of supply.
    - The System Operator can take various additional mitigation actions in ‘stress periods’ by calling on various demand-reduction responses, and latent capacity - generation and other flexibility that is not part of normal operation or is otherwise not available to the market, but which costs far less the VoLL.

160. As illustrated in Table 1, there are several forms of such latent capacity, which could be material.

Specific situation	Major Components	Descriptive Shorthand of situation
Involuntary disconnections	Domestic consumers Industrial consumers	Security
Reserved (exceptional) measures by System Operator (or DSOs)*	*Emergency actions:* Max generation, Frequency reduction *Load eg.* voltage *reduction* (CLASS)	Stress
Other services contracted by SO to maintain adequacy	Contracted demand reductions Industrial backup generation or other "latent" capacity	Other Contracted Reserve
Active demand side response	Consumers differentiating loads between essential and discretionary uses / timing	Consumer Load differentiation
Rising market prices reflecting growing scarcity	Use of peaking plant and in-market demand response and storage	Tight market
Normal market	Normal market operation	Normal market

SO = System Operation, DSO = Distribution system operator

Table 1: Options as the system tightens

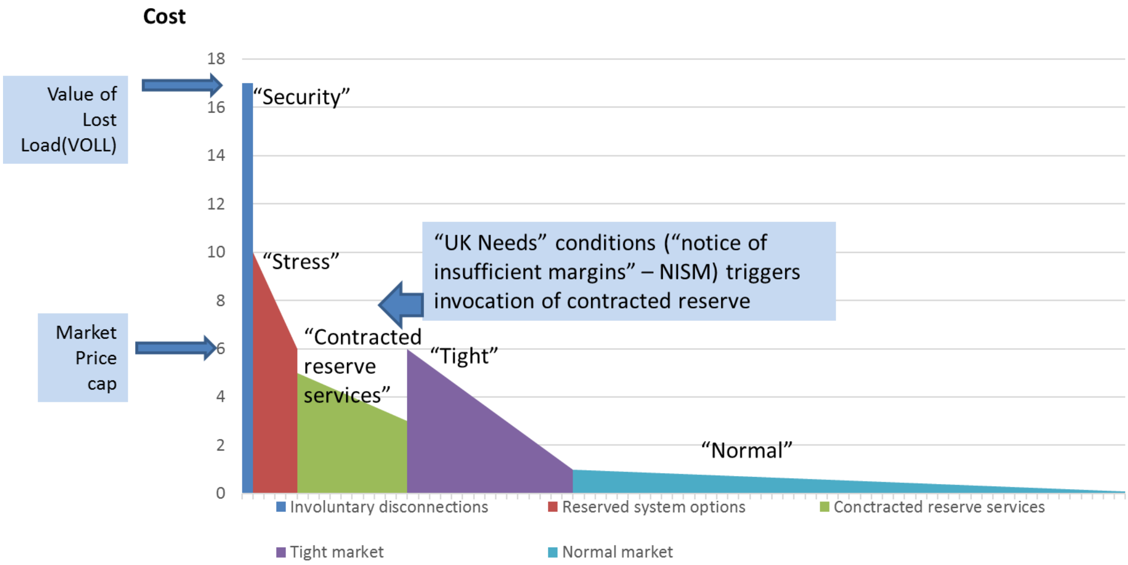

Figure A3-1: Conditions and options as electricity margins tighten – schematic
Source: Authors

Figure A3-1 illustrates these different conditions of the system, and how they reflect rising costs and potential actions, rather than a simple "cliff edge" if the natural demand exceeds the normal available generating capacity. It offers a terminology. More generally we suggest that a simplified set of generic terms are defined that enable these issues to be discussed and communicated, as we believe this could help to bring what is currently a relatively obscure and dark corner within the System Operator's toolbox into mainstream discussion.

161. Figure 2 below, taken from an academic paper on this issue,[31] illustrates in more detail the countermeasures potentially available to avoid disconnections as the gap between normally traded generation capacity and net demand at the grid supply points tends to narrow, and indicates relative prices that either the normal market will pay to maintain balance or the price that the System Operator would negotiate and pay on behalf of and at the cost of consumers. Each of these mitigating actions, however, costs less than the VoLL assumed at the point of disconnection which we use for the purposes of evaluating capacity to procure.

162. These actions would be invoked before finally having to selectively disconnect some loads (NOT switching off all the lights). Obviously, the system should not rely on having to operate 'under stress' for extended periods, since all these options are costly and generally non-firm, and some (notably storage) may only be available for limited durations. Yet clearly, 'Loss of Load Expectation' is a misnomer for a statistical measure of the probability of invoking such mitigation measures. However, these measures are implicitly valued at £17/kWh –over one hundred times the consumer price. One might doubt if consumers would be willing to pay £17/kWh rather than experience barely noticeable actions by the System Operator or occasional brown-outs, particularly as the lights actually go out for 1-2 hours per year on average because of local faults of storm disruptions to transmission.

[31] D. Newbery and M. Grubb (2015), 'Security of Supply, the Role of Interconnectors and Option Values: Insights from the GB Capacity Auction', *Economics of Energy & Environmental Policy*, Vol.2 no.2.

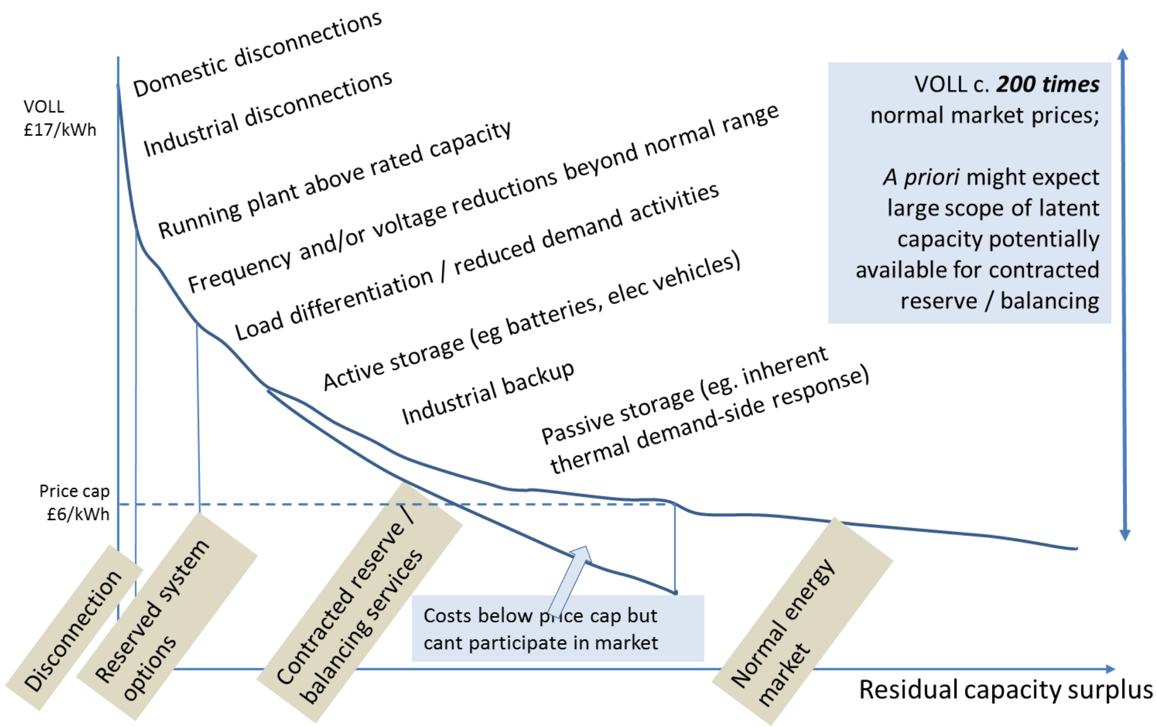

FIGURE A3-2: Supply curve of options and 'latent capacity' for responding to tight system conditions
Source: Newbery and Grubb (2015) (see note 31).

163. In an idealised system, there could be a whole schedule of measures that could come in if and as a system tightens. Many might arise in market response, on demand-side with consumers saving money by becoming increasingly active in differentiating or scheduling loads (such as electric vehicle charging) according to the power price.

164. Further along to the left, recent experiments with Customer Load Active System Services' (or "CLASS") explored the impact of voltage reductions at peak times, with many interesting findings (see Box)[32].

[32] http://www.enwl.co.uk/class

BOX 2: The CLASS project on voltage reduction

The possible role of voltage control has been explored by Electricity North West in the 'Customer Load Active System Services' (or "CLASS") project, publicly funded through the Low Carbon Network Fund set up by Ofgem[1]. A key objective was to manage peak demand by adjusting voltage ***without customers in the trial areas noticing any adverse effects on their electricity supply when the voltage control was applied.*** Many aspects of voltage control were trialled, covering active and reactive power, domestic, industrial and commercial and mixed sectors and response times. The outcome was positive, showing amongst other things:

1. In the domestic sector, a 1% change in voltage lead to a 1.3% change in real power;
2. In the mainly industrial and commercial sector, a 1% change of voltage lead to a 1.48% change in real power
3. If this was applied nationally this would represent about 900MW at peak demand period. The trials, amongst other things, also considered the relationship between voltage control and reactive power, which is given very little consideration in the current analysis of capacity requirements because historically, this has been unnecessary due to the abundance of rotating plant. With increasing asynchronous generation, we suggest that capacity must be considered in all its dimensions going forward.
4. We are aware of a number of independent companies who have developed equipment and software that can respond to voltage and frequency changes within Enhanced Frequency Response timescales and which can deliver harmonic suppression, power factor correction and phase balancing along with smart voltage control. This allows the possibility to liberate much of voltage control from the "emergency Actions" regime into the new world of the smart grid.

This example of voltage control is but one that might be repeatable across other actions currently viewed as Emergency Actions (except perhaps MAXGEN).

165. This would imply a far more refined version of "Value of Load Lost", not as a cliff-edge but rather reflecting the value of mitigating actions that could be deployed to avoid any involuntary disconnections. This is illustrated below in Figure A3-3, which suggests that a number of the mitigating actions can be ultimately sourced through development of markets in 'tight flexibility' and 'latent capacity'.

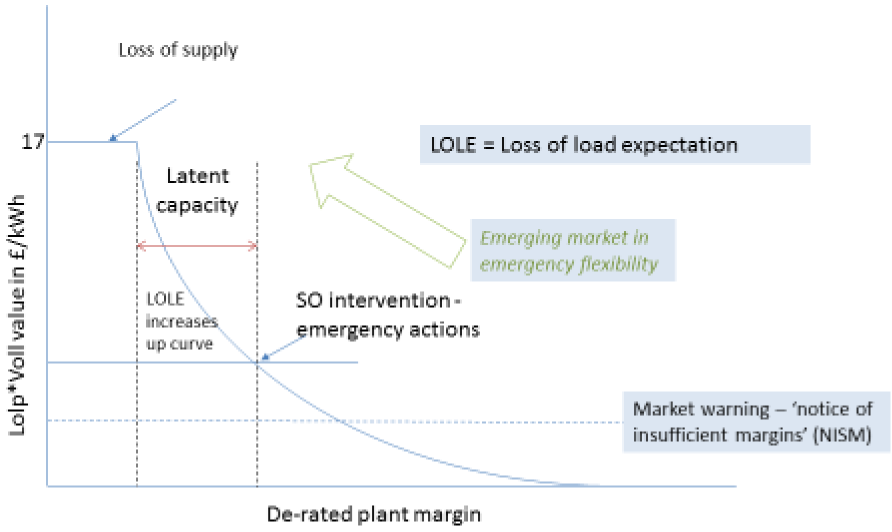

FIGURE A3-3: Supply curve of options and 'latent capacity' for responding to tight system conditions

166. Drawing all this together, the essential point of concerns expressed in previous PTE reports is that the Value of Lost Load is calculated on the basis of imposed involuntary disconnections, but then applied to capacity consistent with other, lower cost flexibility measures. We estimated that this difference equates to at least 1.5 GW, the controllable element of which represents an unseen excess capacity. The net costs of this are borne by consumers under the current assessment of future capacity needs even after allowing for the benefits of enhanced security of supply.

167. We believe that the scale of this potential and its implications needs closer examination, set in the current and potential evolution of the electricity system. The underlying drivers of system evolution include the increasing proliferation of ever-cheaper sensors, information networks and algorithms that allow huge amounts of data to be analysed in near-real time and actuators that can automatically or autonomously control devices and systems. Together with storage and voltage / frequency control systems, these are the infrastructure elements required for smart networks and the internet of energy to evolve. The plummeting cost of storage, and its growing inherent availability in the form of electric vehicles – which bring both new demands but also new flexibilities - amplifies the importance of taking account of these possibilities in evaluating system capacity requirements.

168. Today, however, while we are seeing the first steps towards that future, we need a much simpler and practical approach. One such approach might be to acknowledge and estimate values of 'voluntary load limitation and latent capacity', distinct from

'involuntary lost load' – so estimating both the scale and cost of some of the elements to the right of the left-hand side of Figures 1-3.[33]

169. However approached, we anticipate that a number of measures currently defined as 'Emergency Actions' in the Electricity Capacity Regulations, could become more normal operational procedures, because they need not be at the instruction of National Grid and could be the subject of a bilateral contract with the system operator, DSO or aggregators, reflecting costs as appropriate. However implemented, the first step would be a careful evaluation of the potential and the possible implications.

[33] This might also be achieved by assessing both the potential contribution of each set of Emergency Actions an appropriate "derating factor" and then subtracting this de-rated contribution from the amount to secure. This may be relatively simple, but not necessarily easy because of the way legislation is structured in the Electricity Capacity Regulations.