Department of Energy & Climate Change

EMR Panel of Technical Experts' Final Report on National Grid's Electricity Capacity Report

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Executive Summary

1. Immense efforts have been made and outstanding progress has been achieved by DECC and National Grid in the current Capacity Market Report compared with its predecessor in respect of interconnectors. Previously these were not recognised as making a net contribution to supply security in terms of volume of capacity required through a capacity market, except in a few sensitivities, however in the latest analysis interconnectors are assumed to provide several GW of equivalent capacity in NG's central cases.

2. The PTE was generally content with the methodologies, assumptions, scenarios and sensitivities in the analysis of the kind that we commented on in our previous report, and we noted continuing improvements in the use of evidence to estimate key input assumptions such as generator availabilities.

3. Consequently, although we are aware of and have pointed to areas where analysis can be improved further, we are generally content that the recommended target capacity is consistent with the reliability standard within the limits of the knowledge and information available. We are also content that the Least Worst Regrets approach to selecting from a number of equally probably options is the best way to reflect a conservative approach to risk.

4. A new feature of this year's Capacity Market Report is the necessity to specify the percentage of interconnector nameplate capacity ("derating factor") that can be expected to contribute to UK security at times of system stress. We have reviewed the methodologies and assumptions to derive the derating factors in considerable detail and we are content that they are reasonable.

5. The inclusion of interconnectors in the 2019/20 Capacity Market precipitated new analytical and conceptual challenges not previously encountered. Inevitably, we found that certain concepts and data are only partially adequate on this occasion and we have made recommendations to develop these areas for future auctions.

6. Key areas for future development include the estimation of Value of Lost Load ("VoLL"), which hitherto has been expressed as a single figure corresponding to the value to consumers of being disconnected from the network. In reality, VoLL is a complex function that depends on factors such as volume, frequency, duration, severity, forewarning and predictability of loss of load events. This suggests that future analysis should include a supply curve of increasingly costly actions to help avoid unannounced disconnections reflecting the costs of unserved energy rather than valuing all unserved energy at a single VoLL. This will be crucial when balancing the cost of increments of security against the value of certain degrees of quality of security to consumers. The effect of properly costing System Operator mitigation actions that fall short of disconnections would, in our view, necessarily reduce the amount of target capacity, perhaps by at least as much as 0.9 GW.

7. Certain older historic data (such as learning from previous market arrangements, historic trading data, demand data and knowledge of demand side responses) that might have been extremely useful to the analysis has not been retained on grounds of cost (- NG is not funded to carry out this function). In a number of circumstances, we pointed to the relative value of information compared with the cost of obtaining or retaining it.

8. We acknowledge the considerable efforts that have been made by Grid and DECC to validate, and act upon, the recommendations in our previous reports, particularly in relation to investigations into demand side response and interconnector behaviour during periods of system stress. We remain concerned that the National Grid's analysis of DSR under-estimates the potential response, even under the current design arrangements, given ongoing technological advances and strong incentives for embedded generation. We have therefore recommended further research.

9. We also remain concerned about what we believe is a potential tendency to double count the impact of extreme weather events (although we do not say that it has taken place in the current assessment). National Grid takes the view that since loss of load is probabilistic, losses of load are unlikely to occur smoothly and regularly, but might appear as several loss-of-load events in one single year and therefore extra capacity is required to provide a safeguard against such events. We argue, however, that this is tantamount to driving ex-post loss of load towards zero hours because the reliability standard specifies that the long term average of loss of load and already includes the specified target three hours lost load per annum within the analysis. We have therefore recommended further analysis to resolve this. We believe that it should also be stressed that loss of load does not necessarily imply power cuts.

10. Separately from the normal role of the PTE, the PTE was asked by DECC to suggest methodologies for choosing a single derating factor for interconnectors from the ranges presented by National Grid. We were careful to avoid taking this to the extent of recommending any specific derating factor as that is a matter for DECC. We did, however, agree with DECC that our preferred approach (application of Least Worst Regrets) was sound in principle but currently unworkable in practice. In these circumstances our view is that the next best alternative that is available to us is to use a simple average method. We also considered using a more qualitative form of Least Worst Regrets which uses a less mechanistic assessment of the costs and benefits of over or under-estimating the DRFs and which could take account of the optionality of delaying decisions. Our view was that this latter approach would be considered too subjective and that the transparency of the simple averaging approach was therefore the best available option.

11. In summary, based on the methods and assumptions used to calculate the target capacity and always subject to our recommendations to improve future analyses, the PTE is content that the recommended target capacity and the interconnector derating factors are defensible, given the assumptions on VoLL, but conservative. We remain concerned that the final figure incorporates over-procurement resulting from an

inadequate understanding of the potential costs of mitigating actions. We believe that reviewing the value of lost load assumption should be prioritised for future auctions.

Introduction

Role of the Panel of Technical Experts

12. The Government commissioned, 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.

13. 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 second report focusing on scrutinising the analysis that informed National Grid's 2015 Electricity Capacity Report and recommendation to the Secretary of State on the target capacity for the December 2015 T-4 capacity auction.

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

15. This report has been prepared for DECC by:

- Andris Bankovskis;
- Dr. Guy Doyle;
- Professor David Newbery CBE FBA;
- Professor Goran Strbac

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

Scope

16. 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 the ones DECC provides); and the outputs from that analysis - scrutinised in terms of the inputs and methods applied. The Dynamic Dispatch Model (DDM) used by National Grid for it modelling is subject to a well-documented Quality Assurance process and the PTE does not comment further on this.

17. The PTE has no remit to comment on Capacity Market or wider EMR policy, Government's objectives, or the deliverability of the EMR programme. 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 PTE is also not responsible for recommending a target capacity to secure in the auction.

18. This report is the PTE's formal report on the scrutiny of the analysis undertaken by National Grid on the amount of capacity to secure through the Capacity Market auction in December 2015 for 2019/20.

19. This year, as a result of legislative changes on eligibility, interconnectors can now participate in the Capacity Market. This report will therefore also comment on the ranges that National Grid has recommended for each interconnector from which the Secretary of State will choose the final figure.

Progress on the PTE's Previous Recommendations

20. The PTE made a number of recommendations in its 2014 report. This section briefly summarises these recommendations and actions which have been taken in relation to them. In general, the PTE is pleased with progress.

In relation to selecting a target capacity:

21. **Previous Recommendation 1**: that in deciding its final recommended "target capacity", National Grid should take full account of the evidence available on interconnector capacity credit, such as that mentioned in this report. This includes the reports it commissioned from Pöyry (2012) and Redpoint (2013), both of which National Grid cites in its Report.

    a. **Progress**: This has been progressed through the studies carried out by Pöyry and Baringa as well as National Grid's and DECC's own analysis.

22. **Previous Recommendation 2**: that in applying the Robust Optimisation methodology, account should be taken of any further information relating to the relative likelihood of scenarios and sensitivities in order to minimise distortion.

    a. **Progress**: The PTE believes that this has been only partially accepted (see paragraph 58) as National Grid still holds that extreme weather events, whose probability can be estimated, should be treated as being equiprobable with scenarios whose probabilities are unknown and moreover, that such events deserve additional consideration outside of LoLE. However, analysis was undertaken to understand how weighting could be incorporated and sensitivity analysis demonstrated it was not material for this year's recommendation.

23. **Previous Recommendation 3**: that a proper quality assurance review is undertaken of the Robust Optimisation model to provide comfort that the model and associated procedures are fit for purpose.

    a. **Progress**: National Grid confirmed that this is ongoing good practice.

In relation to understanding better interconnector capacity credits:

24. **Previous Recommendation 4**: that National Grid is encouraged to commission further theoretical work on, and statistical analysis of, the deliverability of UK-Continent interconnectors during GB stress hours alongside and in support of the ENTSO-E programme.

    a. **Progress**: DECC and National Grid has gone to some considerable lengths to complete this as far as has been possible within time and resource constraints. There is more work to be done, but we are informed that this work is continuing.

25. **Previous Recommendation 5**: that the rationing rules and curtailment sharing agreements for interconnectors are kept under close observation, and that DECC should, either directly or through Ofgem's membership of CEER, request ACER to ensure that price caps on Euphemia are at least raised on the intra-day and balancing markets to allow sudden scarcities to be resolved in a timely and efficient way.

    a. **Progress**: This has been pursued as far as has been possible given that other institutions and states determine in large part the rate of progress. This action is therefore expected to be on-going.

26. **Previous Recommendation 6**: that National Grid works with RTE and more widely, continue to work through ENTSO-E to further develop a proper regional model to assess the deliverability of UK-Continent interconnectors during GB stress hours, and that as part of that it reports on the relationship between GB day-ahead and balancing prices during past periods of stress.

a. **Progress**: This is underway as part of a larger ENTSO-E project.

27. **Previous Recommendation 7**: that National Grid continues to work with SEMO and the SEM Market Monitoring Unit to evaluate the joint probabilities of stress events in GB and the SEM, and that they further analyse the ability of the SEM to import over the Moyle while exporting over the EWIC under the Euphemia rules, and ensure that if necessary this is an option that is readily called upon without it being deemed an emergency action.

    a. **Progress**: This does not appear to have been referenced in the 2015 Capacity Report and we still need a discussion of the SEM-GB interconnectors and how they will be managed when coupled if the Moyle needs to import while EWIC exports.

28. **Previous Recommendation 8**: that National Grid and/or Ofgem be required to keep and maintain full information about past system performance, including information about prices (contract, day ahead, balancing for wholesale power, fuel and carbon), generation availability and output by plant, demand, and congestion, interconnector use (and prices at the other end of interconnectors) beyond the apparently current seven year cut-off, to ensure that data for longer time period analysis remains accessible for analysis.

    a. **Progress**: We understand that there are resource implications involved in increasing the scope and duration of data curation that are matters for National Grid, DECC and Ofgem to resolve if, as the PTE does, they consider the value of retaining such data exceeds the cost. In passing, we would suggest that this might extended to include spot and intraday and balancing price data on each end of all interconnectors.

In relation to Distributed Energy Resources

29. **Previous Recommendation 9**: that a programme to research the full potential of DER should be instituted as soon as possible to inform future auctions with particular focus

on the full range of peak demand mitigation resources that are referred to in this report.

a. **Progress**: This recommendation is being pursued by DECC through focussed DSR research. At the time of writing, we have seen only a draft of the research being carried out on this by consultants for DECC. We would also point out that the response to Transitional Arrangement Auctions and the DSBR over the next two winters should deliver useful information.

In relation to key generating plant metrics to enable the assessment of security of supply:

30. **Previous Recommendation 10**: that the average forced outage rate during periods of system stress calculated against the full net rating of the plant (TEC) should be established as a key reportable indicator of the contribution of all types of controllable generating plant (including embedded generation).

a. **Progress**: National Grid has taken account of the findings of the ARUP report on plant availabilities. We think that the need to understand and quantify embedded generation remains an important ongoing issue for the future.

Approach

31. 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 target capacity for the Capacity Market and the PTE has had opportunity to question National Grid during the development of its analysis and recommendation.

32. To carry out its work, the PTE met with National Grid at DECC's offices, approximately on a fortnightly basis since mid-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 produced various interim reports and put many questions to National Grid to which DECC organised responses.

33. 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 second auction, and specifically the role interconnectors are now expected to play in the capacity auction. Their inclusion raises new questions, and requires additional modelling capability not just for GB but for the countries to which we are interconnected.

34. 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 contribution of interconnection;
    b. demand side response in general;
    c. the treatment of extreme peak load events; and
    d. established methodologies for making a rational choice from a large number of possible target capacity figures under circumstances of uncertainty.

35. The inclusion of interconnectors in this year's auction is a big change and, to support the Secretary of State's decision in choosing the target capacity, the PTE commented on National Grid's ranges and also proposed a method for choosing the final figure to the Secretary of State.

36. 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-procurement, and so could be expected to argue for a high level of procurement and perhaps stress the risks of under-procurement more than they might extol the cost-saving advantages of under-procurement. 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.

37. This report is not comprehensive and nor is it a due diligence exercise but the PTE believes that it has nevertheless identified some extremely important issues that have significant consequences that are discussed here. Accordingly, the PTE has not overly focussed its attention in this report on the myriad of detail of many matters which were raised and satisfactorily resolved or are part of on-going development.

38. This report has been prepared from information provided by DECC, National Grid 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 considering investment must make their own independent assessment having made whatever investigation that person deems necessary.

Analysis and Key Findings

National Grid's Recommended 'Target Capacity'

Introduction and context

39. Summary of PTE's views on Grid's analysis: The PTE has examined all the components of the modelling that National Grid has deployed to determine the amount of capacity to secure in the auction, and comments on these below. Our main finding is that we are broadly content with National Grid's methodology, however, it errs slightly on the side of over-estimating the target capacity, although the information to make a better calculation is not yet available, in particular, an appropriate Value of Lost Load (VoLL) assumption as explained later.

40. Rationale for a Capacity Market/Missing money: The main justification for the capacity auction was that there is a "missing money" problem in that the VoLL estimated by DECC at £17,000/MWh (based on a report jointly commissioned by DECC and Ofgem) considerably exceeds the price that the System Operator can charge for mitigation actions in stress events (£6,000/MWh). Simplistically, if the LoLE is 3 hrs/yr, the missing money is (17,000 – 6,000) £/MWh x 3 hrs/yr = £33,000/MW/yr or £33/kW/yr. Investors also worry that policy changes are both unpredictable and could considerably influence future energy wholesale prices. Thus Germany's enthusiasm for solar PV has caused wholesale prices to fall by perhaps on average €6/MWh, removing almost all the clean spark spread and undermining the case for investment in gas generation (new coal is effectively ruled out either explicitly in the UK through the Emission Performance Standard or in other countries by the threat of future more aggressive carbon price action). The market coupling agenda is only part-way complete, and still lacks intra-day and balancing trading. The Energy Union announcement in February 2015 speaks of further future market reforms, not least to capacity mechanisms and pressure to reform renewables support mechanisms, further adding to market uncertainty.

41. The importance of getting the target volume right: If the Government sets too high a procurement volume, then the future market will have more capacity than is efficiently required, and this will reduce stress hours, and hence the high prices that would otherwise be expected in those hours. This reduces the revenue that plant can expect to earn in such hours, and raises the required capacity payment. More plant means for many plant a lower capacity factor, and hence again less revenue. Fewer stress events reduces the incentive to ensure that all the relevant very short-term markets within and between countries work efficiently, further reinforcing the need to counterbalance their absence with a capacity mechanism. In short, excessive procurement in a capacity auction undermines the self-correcting actions that the market might have taken and risks locking us into a Single Buyer Model in which almost all capacity needs a contract to enter the market.

42. Setting the target volume too low could, in the extreme, jeopardise meeting the LoLE security standard, but this merely means that the System Operator will be required to employ mitigating actions more often than 3 hours per year. The new Balancing Services that National Grid has procured will make such mitigating actions more effective and will likely be tested in the next winter. The sharper price signals that the reformed Balancing Mechanism provide[2] should also reduce the number of hours when mitigation actions occur, and their role has not yet been properly tested. Setting the target volume too low and therefore procuring less simply avoids foreclosing the opportunity for capacity to come forward at a later auction, and in the meantime, additional information and learning can be acquired to refine the analysis of need even further. This would be a practical way of compensating for the exclusion from the National Grid analysis of the optimum time to procure but it is beyond the scope of this report to comment further on this.

43. This is particularly important in a period in which DG COMP is actively investigating capacity remuneration mechanism (CRMs). The State Aid Guidelines allow interventions when there is a clear market failure to be corrected, but they require that the intervention is the least cost and least distortive method available. Market solutions are preferred, and a capacity auction scores high on this, but excessive

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[2] https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision

procurement undermines the market and scores badly on that account. The recommended target capacity in 2014 (though not necessarily the capacity actually procured) probably overstated the domestic capacity requirement by understating the contribution interconnectors make, and fortunately that problem is now being addressed leading progressively to more reliable analysis.

44. Main issues the PTE have identified: These are mainly based on the assumption used to finely balance the recommendation when faced with uncertainty across a range of scenarios and sensitivities. National Grid uses a Least Worst Regrets (LWR) framework that considers the trade-off between the cost of capacity (the net Cost of New Entry, NCONE) and the benefits in reduced expected energy unserved that it brings (EEU). The PTE are content that this is a robust framework to use but point to significant issues with both NCONE and EEU assumptions. The critical assumption in National Grid's analysis that results in excess procurement is to take the Value of Lost Load (VoLL), set at £17,000/MWh, as the cost not just of unexpected power cuts but of all mitigating actions that the System Operator would take before resorting to disconnections.

Scenarios and sensitivities

45. National Grid describes its scenarios and sensitivities in Chapter 4, and we follow their order of topics.

46. The PTE are satisfied that the specification of the four FES scenarios has been extensively consulted on and based on the best evidence available at the time.

Sensitivities

Plant Derating

47. The PTE considers that testing the sensitivity of the results to high and low plant availabilities is helpful, and the reasons for rejecting some of the sensitivities around plant availability appear well-founded.

48. The PTE also notes that National Grid has updated the generating plant derating factors to take account of the latest annual data. This is consistent with the approach

of basing plant availabilities on recent historical data which is an acceptable albeit prudent approach. The PTE still maintains that these availability rates are below what is considered good practice in jurisdictions which have strong incentives to achieve high availability rates, although we acknowledge that the last decade has not provided a strong incentive to maintain plant to the highest standards.

Demand

49. The demand projections appear to be built on the best evidence available. We note that all the peak demands for 2019/20 are remarkably close together except for *Gone Green*, where the peak demand is considerably reduced, despite that being the only scenario in which heat pumps are prominent, albeit mainly after 2020. Presumably peak shifting of these and other loads more than compensates for their high winter demands.

Demand Side Response

50. Although not material to the target capacity for the auction, we understand that DSR includes some types of capacity that could bid for an agreement with very short lead times as well as other DSR types requiring longer investment lead times. Therefore projections of DSR are material to the Secretary of State's decision of how much capacity to set aside for a T-1 auction, although we appreciate it is not the only factor.

51. National Grid's analysis of DSR projections vary with the FES Scenarios, and except for *Gone Green*, have been reduced by 1 GW compared to the 2014 FES projections. This is partly because the DSR experienced in winter 2014 was 0.5 GW lower than projected, and partly because of new analysis by ARUP and Oxera. We accept that the updates are based on the best currently available data from the UK, but also note that the robustness of this recent data is still inadequate, and should be improved as more trials over longer periods involving more customers become available.

52. We believe since it is difficult to identify and quantify demand side response and current estimates are likely to omit capacity (e.g. smaller generation that could be aggregated and growth from DSR from TA and CM policy). Wider concerns that the current policy framework may not unlock the full potential of DSR are not for discussion within the scope of this report.

53. We were given sight of an early draft of a report on “DSR and the Transitional Arrangements” which is being prepared by Frontier Economics for DECC. This report does little to reduce the uncertainty in the uptake of DSR but draws out a number of value streams for DSR and notes that uptake could range from 0.8GW to 3.4GW.

54. The Frontier analysis suggests that well established low-cost DSR technologies, such as existing thermal embedded generation, standby generation and some demand-led DSR that are already used for provision of STOR would face relatively low additional costs to participate in the TA. On the other hand, less developed technologies, mostly demand driven DSR, may face much higher costs associated with participation in TA. This indicates that potentially significant amount of established low-cost generation would need to be auctioned before new forms of DSR are brought into the market.

55. In our opinion, the potential for DSR could be much greater (although analysis is needed on how much of the potential current policy can bring forward). We understand that Frontier and LCP are undertaking a second phase of research focusing on the long term potential of DSR in the UK which is encouraging.

56. **Recommendation 11**: Additional analyses should be undertaken to understand the full, absolute potential of DSR in addition to its potential within current market arrangements so that future analyses can anticipate the contribution it may make

Interconnector Capacities

57. National Grid is probably best placed to judge the realism of the interconnector commissioning dates and capacities embedded in the scenarios, which cover a range of plausible configurations. We note that there is little variation in their projected capacity in 2019/20 but the range understandably widens in future years.

Extreme Weather

58. The Reliability Standard is central to understanding the intention of all the modelling and recommendations. Here we attempt to clarify important aspects of the PTE’s interpretation of the Reliability Standard, as this is not discussed extensively in National Grid’s Report. (We do not repeat the detail of the methodology here as National Grid provides an excellent description in its Report).

59. The Reliability Standard is defined as a loss of load expectation ("LoLE") of three hours per annum. A loss of load is not equivalent to blackout; rather, it represents the number of hours that the market has not met demand and when National Grid needs to use its reserves and tools to balance the system (the very last option being customer disconnection). We do not question the policy decisions regarding the use of the LoLE or the value chosen (as to do so would be outside our remit) but we are obliged to interpret it in order to comment on whether it is used correctly for analysis purposes.

60. LoLE is a long term average (i.e. covering a number of years that is fully representative of all weather and system states that might occur). If the LoLE is correctly calculated using good data, then the following conclusions would follow:

- Weather can present considerable variations which, combined with plant and system states can present wide variations in capacity margins at times of system stress from one year to another. The ex-ante calculation of LoLE may therefore differ considerably from the ex-post loss of load that actually occurs in any single year.

- A "loss of load" event means that the System Operator needs to take mitigating actions (as LoLE is defined before mitigation) and therefore in most cases does not lead to blackouts or even power cuts.

- Even if power cuts were to occur, the cost to consumers has already been calculated to be outweighed by the benefits they receive by paying for appropriate, rather than excessive levels of capacity. If GB procures excessive capacity it will mainly benefit more prudent countries to which we are interconnected as they will be able to import from us when the value to them is higher than to us.

- It is incorrect to argue that additional capacity, above that needed to meet LoLE, is required to cover extreme weather events. LoLE already incorporates rare extremes and providing for these events again would be double counting. An accurate recalculation of LoLE would show that such an action would actually drive LoLE towards zero thereby undermining the integrity of the LoLE standard.

- For the same reasons as in the previous point, it is also incorrect to assign extreme weather events the same probabilities within the Least Worst Regrets calculation of the target capacity as this over-estimates the required capacity.

61. Bearing in mind the above, we draw attention to the arguments presented by National Grid in §4.3.5 of its Report ("Weather – Cold Winter"). National Grid states that "*LOLE is a first order metric, which is highly non-linear and so not including the sensitivity fails to fully account for the non-linear impact of increasing LOLE and therefore understates its impact.*". The 'sensitivity' referred to is based on a recent cold winter and calculates LOLE assuming that the weather that occurred in 2010/11 is repeated. National Grid correctly points out that this could mean that is it possible that in a ten year period, there could be no loss of load or disconnections for nine years and thirty hours in one year, which meets the Reliability Standard, but which National Grid considers has a disproportionately high impact on consumers. We also accept that National Grid has only 10 years of comparable weather and demand data, and is rightly concerned that this will fail to pick up their claimed non-linear impact of very cold weather.

62. We agree that such an outcome is possible, but we point out that if 30 hours loss of load were to occur in a 1 in 20 year winter, this would not by any means imply that the whole of GB would be in darkness for a continuous thirty hours.

63. To appreciate why ***thirty hours loss of load in any one year does not remotely imply a long and sustained GB blackout***, consider the time-evolution of the events. LoLE does not contain any information about the volume of a shortfall in supply. As the figure in 69 illustrates, high impact events occur with far lower frequency that low impact events. Thus 30 hours is likely to contain a preponderance of low impact events which can easily be managed. Moreover, having forewarning of a sustained period of cold weather allows prudent steps to be taken to manage and mitigate these foreseeable events. We know that water consumers respond to requests to reduce water consumption by sacrificing individual needs for the good of the many. There is no reason to believe that self-interest would prevail over our altruistic survival instincts

when it comes to preventing loss of load. Consumers may be expected to respond well if asked to postpone their use of non-essential electricity use to another moment in time whilst meeting essential needs. We therefore would not agree that the impact is “non-linear” or “disproportionate”. Indeed, during a 30 hour event series, it seems more likely that preparedness would decrease the cumulative impact and cost compared with more frequent but unexpected Loss of Load events that may last less than an hour each.

64. We explore this further by discussing two key issues: first we need to consider the consequences of a much longer loss of load in any particular year; second, we consider the deeper assumptions with the LoLE calculation that may be faulty. This brings us to an examination of National Grid’s methodological treatment of loss of load events.

Methodology

Dynamic Dispatch Model

65. The PTE commented on the Dynamic Dispatch Model (DDM) in its previous reports and we see no reason to change our view that it is a suitable model to calculate the overall total target capacity. We note, however, that the DDM has been improved to better model flows over interconnectors making it more suitable for the inclusion of interconnectors in this year’s Report.

The Value of Lost Load ("VoLL")

Impact of Ex-Post Loss of Load Exceeding LoLE in a particular year

66. At issue here is the impact of a tight capacity margin at times of system stress at the point where "loss of load" occurs when the number of ex-post hours significantly exceeds the ex-ante LoLE in a particular year. This carries with it a fear that long drawn-out blackouts may result, whereas we argue that this is not necessarily the likely outcome.

67. First, it is unlikely that the "loss of load" is concentrated within one continuous time period and it is more likely that it is spread over a number of peak periods on successive days. In such cases, the normal mitigating actions would be available and "loss of load" would not necessarily lead to long periods of disconnection for most customers, and certainly not to a blackout.

68. Second, there will be significant opportunities for management of supply deficits, which will minimise the cost of interruptions experienced by consumers including measures additional to those which were adequate historically but which may now need augmenting and updating. Suggestions for such mitigation include:

    a. In some circumstances it would be possible to inform consumers about supply shortages ahead of time, which would lead to significantly reduced VoLL (and hence corresponding cost of interruptions) as computers can be backed up, key tasks can be rescheduled and other demand side responses can be encouraged.

    b. In the unusual cases where shortfalls happen without warning (e.g. the loss of more than one power station or key transmission link within a short period of time), electrical power shutdowns could be *scheduled over different parts of the system* for short periods of time hence reducing the duration of interruptions experienced by the individual customers, which will lead to reduced costs of the loss of load (reduced VoLL).

69. Based on unpublished modelling of supply interruptions in GB system carried out by Imperial College, Figure 1 <u>indicatively</u> illustrates the link between the magnitude and frequency of deficits (frequency is expressed as number of occurrences in 5 year period): we observe that the deficit of 500MW is expected to occur 4 times in 5 years (call it once a year), while deficit of 2000MW on average will occur once in 5 years.

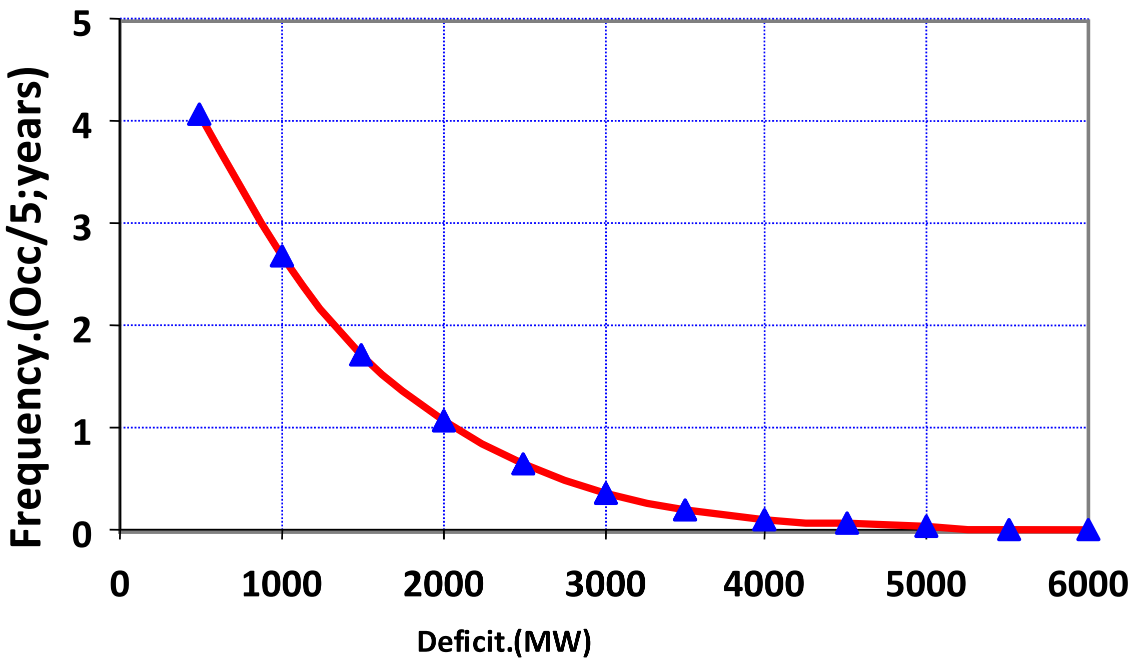

Figure 1 Indicative relation between frequency and magnitude of interruptions

70. Clearly, the deficits are relatively modest in magnitude and there will be hence opportunity to *schedule* these across the system and therefore *reduce the duration of interruptions* experienced by individual consumers leading to reduced VoLL (and hence the actual interruption costs).

71. Regarding VoLL itself, which is a critical input into the Least Worst Regrets analysis, the PTE came to the conclusion that there was a danger of confusing two different ways in which the term was used in National Grid's analysis. While we have

reservations about the level of the VoLL at £17,000/MWh, we accept the attraction of having a single value for an actual (and, for the consumer, unexpected) loss of load, or disconnection. Our criticism lies in using this same value for so-called Loss of Load events, which are events in which the System Operator has to step in with mitigation actions (from Max Gen, Emergency Assistance and demand side responses through to voltage reduction, public announcements and regional loss of load sharing for example) and therefore the intensity of system stress involved.

72. Put simply, a slight reduction of voltage may have a very minimal or no cost impact on consumers, whereas a power cut would have a greater impact on its value to consumers. The detailed structure of the VoLL function, however, is unknown, which in the case of interconnections, for example, would lead to a high risk of setting derating factors too low which in turn leads to the over-procurement of capacity elsewhere at the cost of the consumer and detriment to market development.

73. The PTE has pointed to evidence suggesting the possible lower cost of a Loss of Load event, i.e. one that leads to invoking the capacity obligation by issuing 4 hours ahead of time a Notice of Insufficient Margin (NISM). A NISM does not necessarily (or even usually) lead to an actual Loss of Load, i.e. the lights going out, but rather it requires the System Operator to take actions as the market has failed to deliver a balance of supply and demand together with the necessary security margin to handle sudden losses of infeed before gate closure.

74. We already know that some (perhaps all) of these System Operator actions will be costed at no more than £6,000/MWh, although it should be noted that was not set to expose the market the full costs of VoLL given the CM already seeks to address missing money assuming a VoLL of £17,000/MWh. However, if markets are working well then GB bid prices should rise in the coupled intra-day and balancing markets at least to £6,000/MWh, and will deliver some amount of extra capacity.

75. Unfortunately, National Grid’s best endeavours to quantify the amounts that could be procured before controlled disconnections (some lights going out) have been

unsuccessful, as such measures have not been needed for a very long time and the methods of deploying voltage reduction have not advanced in line with the technology available. They believe that the amount that can be secured through voltage reductions are now far less (perhaps only 1.5% of demand) compared to the earlier assumption of 7.5%[3], in part because power electronics make many power uses (moderately) independent of voltage, and also the share of tungsten filament lighting, whose demand is highly voltage sensitive, has fallen with new more efficient fluorescent and LED lights.

76. Nevertheless, there is some volume of so-called Loss of Load events that should be valued substantially below £17,000/MWh, and if this were done, the minimum cost point would be at a lower level of capacity under all scenarios. Figure 2 illustrates this, following the format (but not the details) of National Grid's figure 14 for one scenario.

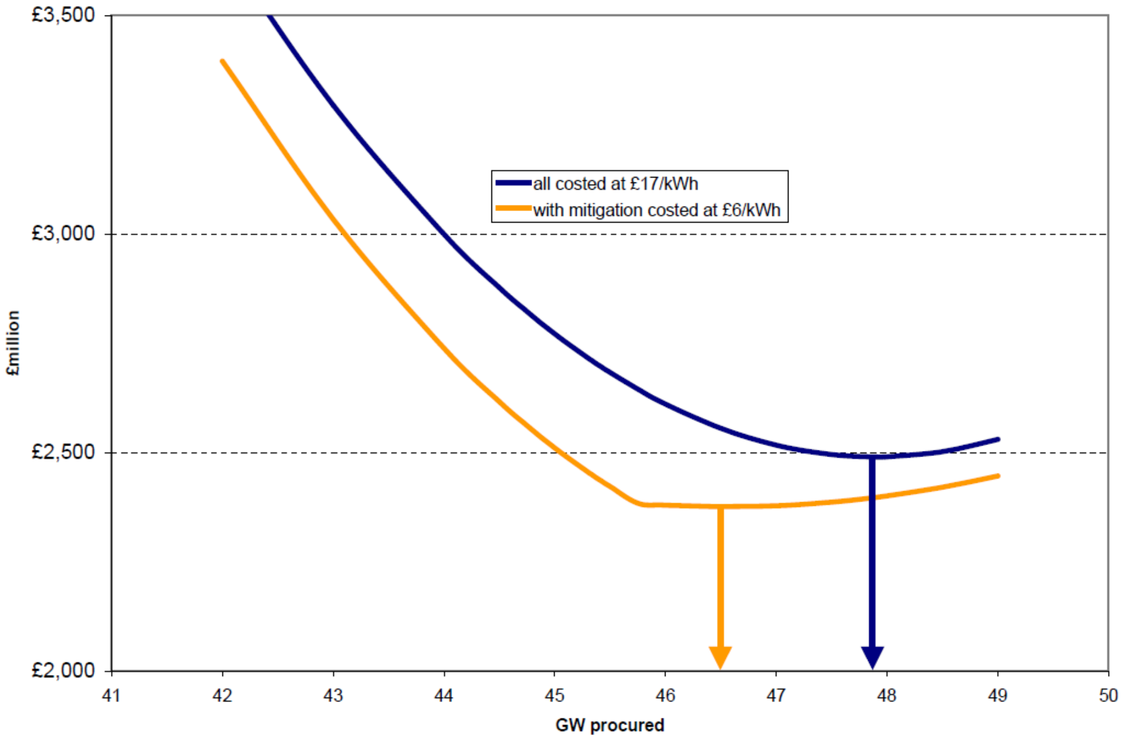

Figure 2 Illustrative cost curves with and without mitigating actions costed at £6,000/MWh

[3] The CEGB estimated that voltage reductions reduce load by 7½% in the 1970s (Bates and Fraser, 1974)

77. Figure 2 shows the combined cost of procuring capacity at £49/kW/yr and all energy unserved (shortfalls that the System Operator has to mitigate) at £17,000/MWh, as in National Grid's Report (the upper line), and the effect of costing 2GW of energy unserved as mitigating actions that are costed at £6,000/MWh, and any energy unserved above that at the full cost of the lights going out, at £17,000/MWh. The minimum point on the total cost curve falls from 47.9 GW to 46.5 GW in this illustrative case. For any scenario, the effect of costing the first energy unserved amounts at a cost below £17,000/MWh will necessarily lower the least cost target capacity, so we can confidently state that National Grid's determination of the least cost amount to procure is necessarily too high, regardless of which scenario is the Least Worst Regrets choice, and the size of the regret, although we cannot say by how much National Grid has overestimated the target capacity.

78. National Grid's Report examines the impact of lowering the VoLL to £10,000/MWh (considerably higher than the maximum amount at which System Operator interventions will be costed at £6,000/MWh). This leads to a reduction in 0.9 GW of capacity to secure in the auction, which, at the net CONE of £49/kW/yr, amounts to £44 million per year. If the 2014 auction price of £19.40/kW/yr were considered a good estimate of what the market expects the net CONE to be (and this may not be the case as it is just one data point in one auction, many bids exceeded this figure and there may be a greater allowance for income through the energy market than was allowed for), then the target volume would be higher by 0.6 GW (see the National Grid's report at §8.4.3 for the analytical detail). We have pointed out that more evidence is becoming available to inform the next cycle of analysis to reset the demand curve, such as the results of auctions, DECC's Impact Assessment, any impact of scarcity pricing and National Grid's mitigation measures. We recognise that the settings for the demand curve are the responsibility of the Secretary of State.

79. National Grid has made some interim estimates of the volume of mitigation actions that fall short of actually losing load at present. These were published in the 2014/15 Winter Outlook Report and Ofgem's electricity capacity assessment reports. However, if, as some predict, we face a tight winter in 2015-16, by summer 2016 we shall have better information on handling stress events without capacity agreements, and should in particular have a better estimate of the volume of mitigation actions that can be undertaken to preserve security of supply. (It should be noted that the specific methods of delivery of mitigating actions will change from time to time. For example,

National Grid's licence for the Strategic Balancing Reserve and Demand Side Balancing Reserve services extend only to 2015/16. National Grid, together with others, may need to design new products to propose and license to enable mitigating measures, which as we mention above, can take full account of new information at that future date and which optimise the use of the system as a whole). We note that ENTSO-E is planning work to harmonise measures of reliability and they might be encouraged to also define and quantify the Value of Lost Load function in terms of key dependent variables including forewarning, timing and duration. This would be relevant to the analysis of reliability and capacity requirements.

80. These considerations suggest the following recommendation.

81. **Recommendation 12**: For future years, National Grid should expand its analysis of loss of load events to take account of the volume, frequency, duration, forewarning and predictability of loss of load events. In particular, National Grid may wish to describe in detail the full range of actions to manage loss of load and their time evolution. These might in future include public information broadcasts to avoid predictable stress events (as has worked successfully in relation to water shortages), the impact of smart technology designed to time-shift electrical load and encouraging DNOs to minimise the impact on consumers by more targeted disconnections when necessary. In the past the French electricity system, which is far more weather sensitive than the British system, has developed a variety of ways that give strong incentives to reduce load in announced stress situations, and lessons learned from those measures might also be valuable.

Quality Assurance

82. We are aware that the quality assurance procedures previously followed continue to provide formal quality assurance for modelling.

Interconnector Derating Factor Analysis

Comments on National Grid's Analysis

83. The PTE argued strongly in our 2014 Report that a more realistic contribution from interconnectors should have been included in determining the amount of GB generation and demand side target capacity in the first auction, and we are reassured that this has now occurred. However, we also note that the full potential implications of more efficient balancing and trading markets mentioned in DECC's June 2014 Impact Assessment have not been fully appreciated in National Grid's Report. This is understandable, in that National Grid insists, correctly, on basing all its recommendations on adequate evidence, ideally of a sufficiently extensive nature to enable statistically robust conclusions. Market coupling for IFA is still at an early stage (although we note that BritNed has been coupled since its commissioning). All the reports (Baringa, Redpoint, Pöyry) that studied the contributions of interconnectors to GB reliability have had to base their assessments on periods before market coupling, and, arguably even more important, on periods of surplus capacity with low maximum prices in the GB balancing mechanism and in GB day-ahead markets.

84. The requirement to include interconnectors in capacity auctions requires an assessment of their contribution to security of supply at times of system stress in the same way that applies to generating plant. We are comfortable with the definition of that contribution in terms of a De-Rating Factor ("DRF") as used by National Grid in §7.2.1 of its Report (where the derated capacity is the nameplate capacity x DRF for the country to which it is connected, which includes its technical availability). Pöyry defined the derating factor as "the percentage of time when GB was importing electricity from an interconnector during identified system stress periods", which we believe is equivalent. The PTE would stress that the outcome of this calculation should imply the retirement of an equivalent amount of GB capacity in order to maintain the LoLE to the required reliability standard.

Range of New Interconnectors Assumed

85. Regarding the range of new interconnectors proposed by National Grid, we note that National Grid is uniquely placed to judge the likelihood of delivery of each proposal. We believe that the assumptions are plausible, as far as we are able to judge. We sought assurances that the judgements in selecting new interconnector scenarios are informed and that National Grid does not regard developers' estimates at face value without scrutiny. We agreed with National Grid's range of scenarios which are designed to accommodate developers' views.

Interconnector Flows at Times of System Stress

86. We recognise that calculating interconnector flows at system stress periods and/or at peaks is extremely challenging given the lack of relevant data upon which to base conclusions. The main problem is that historical experience relates to a time before market coupling when our interconnectors were inefficiently used and could not be relied upon to deliver power in response to GB stress periods. Since February 2014 GB's links to the Continent have been coupled and are now efficiently used, but we have only one mild winter's experience since then to judge, and one with more than adequate capacity. More generally, the period during which studies have been conducted has been characterised by general adequate capacity throughout North West Europe, and in that time there have been no black-outs caused by inadequate capacity.

87. The most appropriate approach would be to run as many iterations of a stochastic a pan-European dispatch model as necessary using forecast demand and capacity to obtain a robust probability distribution in the context of full market coupling. In reality, none of this was possible. First, there is at present no adequate pan-European model available. Second, time constraints would have meant that a full set of runs would have been close to impossible in the time available. Third, as mentioned, we did not have fully coupled markets until very recently and so any model calibration and back-testing was not possible, and so compromises were necessary.

88. National Grid drew on a wide range of evidence and reports in this part of the analysis, which, after considerable discussion and debate, we believe was a well-founded approach in the circumstances.

89. The historical analysis of correlation between flows and price signals carried out by Pöyry for existing interconnectors was thorough and useful. The key judgement was how to approximate to system stress events when extremely few such events have occurred. Using system margin as a proxy for system stress appeared to us to be reasonable and robust. The use of the output to identify minimum de-rating factors was sensible and welcome. Other benefits of the work included the identification of a trend of increasing correlation between price and flow with time, which largely reflects the gradual movement to full market coupling across North West Europe in the period up to the target date for full coupling of 2014.

90. National Grid engaged Baringa to carry out modelling work including new interconnectors to forecast the correlation between price and flow during system stress which implied (though did not claim to predict) derating factors. While we accepted the necessity of the assumptions made, we agree with all involved that there were some severe limitations on its reliability for two main reasons: first, the model only carried out 100 runs, which is far too few to create a stable and representative probability distribution. Second, the model did not include any uplift for scarcity pricing during periods of stress, which we think could have increased the correlation between stress and flow. By definition, a stress period is one in which we are willing to pay very much more (up to VoLL) than the cost of the most expensive generator on the system (the system marginal cost), and so it could be misleading to model stress flows as entirely determined by the system marginal cost. The argument presented to us for not including uplift was based on the low correlation between stress events on each side of the relevant interconnectors. Although this is a reasonable argument, it would be more compelling if it were tested.

91. PTE proposed that National Grid calculate a “Diversity Benefit Factor”, which was subsequently done by National Grid. This benefit arises through interconnection because outages of individual power stations are uncorrelated, and therefore the greater the number of power stations that can deliver to each market, the lower is the total shortfall of generation and therefore the lower is the LoLE for the interconnected combination. This diversity benefit is very high if the number of power stations is low, but decreases as the number rises, which is why adding an additional interconnector to the same system abroad is not as valuable as the existing interconnectors. There is an equivalent diversity benefits from demand to the extent that this is not correlated in the two systems.

92. Other inputs to determining derating factors included historical analysis of the demand-temperature correlation and temperature-wind speed correlation.

93. In spite of modelling limitations, we were generally satisfied that the outputs were a considerable step in the right direction as they suggested far higher derating factors than would have been assumed in the past without the analysis.

94. **Recommendation 13**: DECC and / or National Grid should encourage the earliest possible development of a pan-European dispatch model with the functionality to simulate the behaviour of interconnectors in a variety of market coupled scenarios. We recognise that intra-day and balancing markets are not yet properly coupled and would recommend that informed judgements about how they will be coupled should be modelled, as stress events are more likely to impact these markets.

Country by Country Interconnector Derating

95. National Grid sets out its ranges for interconnector DRFs at §7.2.4, and recommends that the DRF should be a round number at the conservative end of the range. The main defence is that if it is set too low then the target capacity in the T-1 auction can be reduced, but they do not offset that by the countervailing argument that if they DRF

is set too high then more could be secured at T-1. (We recognise that the situation would be more complex because higher demand at T-1coupled with lower demand at T-4 would also stimulate more innovation from demand side response but also less incentive for generators failing to win a capacity contract at T-4 to remain available for T-1 and National Grid refers to the second of these risks at §7.2.4 of its report. We comment on the methodology for selecting a single DRF for each interconnector below and specifically address National Grid's asymmetry in treating under- and over-procurement. The PTE has read the various reports and National Grid's comments on the individual interconnectors, and, with the exception of the link to the SEM, has little to add to their assessment.

GB - France

96. PTE is aware that IFA is now old and less reliable, so its technical availability could be as lower than other interconnectors with France. The PTE also recognises that France is very weather-sensitive because of the high level of electric domestic heating, and that cold conditions in France can coincide with those in GB, so wind/weather correlations are an important determinant of the DRF, supporting the 50-70% range.

GB - Netherlands

97. BritNed is new, presumably reliable, and the Netherlands has adequate capacity and is also well-connected to its neighbours, so we would expect a high value for the DRF on this interconnector.

GB – Single Electricity Market, Ireland

98. The SEM is currently being redesigned to the I-SEM, which will align with the EU Target Electricity Model and ensure market coupling by the end of 2017, well before the 2015 capacity auction delivery year. The SEM projects adequate capacity for the island until beyond 2020. This capacity is concentrated in the south, and Northern Ireland has a falling capacity margin that should be relieved by the commissioning of the North-South Interconnector (NSI). If the NSI is commissioned by 2019, then the I-SEM should normally have adequate capacity to supply exports to GB over its interconnectors in GB stress periods, even though periods of high demand and cold

weather will likely coincide across these links. Plant outages are potentially more serious in the SEM as plant sizes are relatively larger compared to the smaller SEM, but they would not be correlated with GB plant outages.

99. As part of I-SEM, the regulatory authorities and the SEM Committee are consulting on the detailed market design, which will likely include a reformed capacity remuneration mechanism (CRM). The present CRM does not deliver very sharp prices in stress periods, and so it remains unclear how prices will be set for trading over the interconnectors in I-SEM stress periods. If they remain as blunt as at present, and if the balancing reforms in GB are reflected in the as-yet undecided intraday and balancing markets on the Euphemia auction platform, then GB should be able to outbid the I-SEM demand side and secure imports over the two links in GB stress periods. This is subject to the ultimate design of the I-SEM as well as technical considerations, (such as ramp rate restrictions which take account of the high proportion of Irish demand that can be met through interconnection and therefore its impact on security if the flow changes too abruptly).

100. We note the contractual limit on the Moyle to its current TEC of 80 MW (entered into by Moyle because several windfarms connecting to the Auchencrosh - Coylton circuit have the effect that the amount of additional local capacity in the area available to all system users, including the Moyle Interconnector, is significantly reduced[4]). This is despite is capacity of 250 MW, which is expected to rise to 500 MW before the 2019/20 delivery date. To the extent that the on-shore transmission link from the Moyle landing point has the capability of carrying more power, there will be periods in which these wind farms are not fully using their entry capacity, which, technically, could potentially be released in some volume 4 hours ahead of the stress event, as required. The PTE does not have the necessary information to judge by how much on average that would make available, nor whether commercial arrangements could be

[4] http://www.uregni.gov.uk/uploads/publications/SONI_Assessment_-_Benefit_of_Moyle_Restoration.pdf ; http://www.uregni.gov.uk/uploads/publications/110930_MIL_SONI_NG_Capacity_Calc_combined_Sept_2011.pdf

put in place that would make this attractive, but the PTE is not convinced that the 80 MW limit is as restrictive as National Grid suggests.

101. Therefore, the PTE considers that National Grid's range of 2% to 10% to be too low, with 25% being a more reasonable upper limit. At the least a high DRF on EWIC should deliver up to 450 MW and even if the Moyle is limited to 80 MW (which we query) the total of 530/1000 is 53%, so 25% is a cautious compromise given that to achieve more would require full implementation of the I-SEM, less restrictive ramp rates, the timely delivery of the North-South Interconnector and other factors.

BG - Belgium

102. There are concerns about current capacity adequacy in Belgium, and the System Operator Elia is providing regular updates.[5] As in GB, existing plant is aging, and plant availability has recently been adversely affected by unplanned outages at nuclear power stations. To quote from the Elia web-site

a. "Nuclear reactors Doel 3 and Tihange 2 were shut down because hairline cracks were found in the reactor vessels, and these must be repaired.
b. The Doel 4 reactor also had to be shut down due to a technical incident.
c. The Doel 4 reactor was recommissioned just before Christmas (2014). However, 20% of Belgian generation capacity still remains offline."

103. In response, Elia is planning scheduled power cuts if necessary, but is also working hard to alleviate the situation, and is considering the building of new gas-fired power plant for 2019. The PTE would expect that Belgium will take every effort to address its current problems and that there is enough time before 2019/20 for the country to have restored its capacity adequacy, and are therefore satisfied with the range proposed by National Grid.

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[5] At http://www.elia.be/en/about-elia/questions-about-the-risk-of-shortage-in-Belgium

Methodologies to Select a Single Derating Factor for Each Interconnector

Introduction

104. As discussed previously in this report, National Grid has used a number of techniques to derive a range of derating factors applicable to each country's interconnection with Great Britain, with appropriate adjustments for individual interconnectors depending on whether they are currently in existence or planned for the future.

105. We fully recognise that interconnectors have different characteristics from generating plant and that the selection of derating factors cannot be based on the same principles as would apply to generators. For example, although DC interconnector operators can control the volume of power flows, these power flows are intended to be guided solely by the auction clearing platform, Euphemia, under the market coupling rules of the Third Package. (Until the intra-day and balancing markets are similarly dispatched through Euphemia, National Grid can intervene and redirect power flows in real time, but this option will likely lapse assuming complete market coupling before 2019/20).

106. That means that the direction of power flows will be determined by the price differentials between the relevant interconnected markets. The only parameter that can be influenced by the interconnector operator is the availability of the link. Arguably, that means that if GB values scarcity at an efficient level, either we outbid others and secure imports when the price is less that our scarcity valuation, or we export because others are willing to pay more than our scarcity valuation. The DRF is then just the fraction of time we are in the first situation.

107. The links to the island of Ireland (the SEM) are not likely to be coupled until late 2017, but they should almost certainly be fully coupled by the date of the next capacity

auction. As discussed above we consider that the Moyle interconnector between NI and Scotland should have a DRF somewhat closer to its nominal capacity, not to its current TEC of 80MW, but we cannot assess what this DRF should be in the absence of more complete information about the ability to release spare transmission capacity from the landing point in stress periods.

108. National Grid has presented a range of possible weighting factors to be applied that reflect the uncertainty of the information currently available. The PTE agrees with National Grid and DECC that the selection of a precise and accurate derating factor from within the ranges is an inherently complex and difficult task. DECC asked the PTE to make its own suggestions as to how weighting factor could be selected. It should be stressed that it is not the PTE's task to recommend any particular derating factors nor is it to make the selection as to the methodology to be adopted by DECC but we can comment on the pros and cons of different methodologies to be applied, the preferred approach and on whether it is better to err on the side of setting low or high DRFs.

Principles of a Selection Methodology

109. In response to DECC's request, the PTE made a number of suggestions. In making these suggestions, the PTE identified a non-exclusive list of relevant principles and observations that may be used to guide the decision on what approach to apply. These included:

- The derating factors, which reward interconnectors in the same way as generating plant, have a role in **incentivising availability** (although the penalties for unavailability appear to us to be relatively weak in this respect not least because the penalties are capped at the level of the capacity payment and therefore cannot make the interconnector operator worse off than without the capacity agreement.
- The derating factors play at best **a modest role in incentivising investment**. Such an incentive would not be relevant to existing interconnectors. New interconnectors can apply for protection under the 'Cap and Floor' scheme, but capacity payments will increase the set of potentially viable interconnectors that Ofgem would approve, as it reduces the cost of maintaining the floor.

- DECC has indicated to the market that it is minded to ensure that interconnector operators shall be assigned a derating factor that is **no lower than certain historical minimums** that were calculated by Pöyry in its historical review of the correlation between interconnector flows and price differentials at times of system stress (unless there are publically reported concerns about the security of supply outlook for the market in question, in which case they would receive the forecasted DRF). This has given a signal to the market that would be undesirable to weaken.
- The setting of DRFs should not be influenced by political considerations, the views of industry and especially cases where there are no market governance rules in place (such as where the Euphemia cap is exceeded or other cases involving system operator intervention).
- Any methodology needs to be transparent, meaning that it has a rational basis within the limits of the knowledge available, is explicable and reproducible.
- Any methodology should aim to be consistent with EU capacity mechanism principles as expressed by the EU Commission, ENTSO-E and the UK's partners overseas who are simultaneously developing capacity mechanisms (such as France).

Suggested Methodologies

110. The PTE suggested consideration of three main methodologies, recognising that each offered a trade-off between rigour and practicality as we are aware that full rigour will require further research and validation. The three methodologies suggested by the PTE were:

- The application of the Least Worst Regrets ("LWR") methodology applied to a pay-off matrix similar to that used to select the "Target Capacity" in the capacity mechanism auction, and a variant of this which considers average pay-off values;
- Taking a simple average of the ranges estimated from the different statistical and modelling techniques;
- A modified more qualitative form of LWR which uses a less mechanistic assessment of the costs and benefits of over or under-estimating the DRFs and take more account of the optionality of delaying decisions.

111. The application of a formalised LWR calculation presented a number of advantages compared with other methods, including:

- It is broadly the same approach as applied for selecting the overall "target capacity";
- National Grid, DECC and the PTE are well versed with the principles of applying LWR to uncertain pay-offs, and market participants appear aware and comfortable with this approach;
- It is a mechanistic approach which does not require judgement to derive a result once inputs are selected;
- It addresses adequately all the principles stated in paragraph 109.

112. While National Grid built the LWR model for assessing the target capacity to secure in the auction, it has been DECC and the PTE that have jointly explored the detailed application of the LWR to the issue of de-rating interconnections. National Grid has assisted in providing output from its scenario modelling mainly providing levels of expected energy unserved (EEU) and the capacity supply costs.

113. The most critical element in the modelling is to construct a table which for different interconnector derating factors compares payoffs between the costs of procuring capacity with the cost of unserved energy across a range of target procurement levels. These target procurement levels can either be set to match the estimates of DRFs generated using other analytical approaches (as reported in National Grid's Capacity Market Report, or as set of round number increments across a broad range (for instance, 20% to 80% in 10% steps). Once this table is constructed, the remaining calculation is deterministic.

114. A detailed model was adapted from National Grid's existing LWR model and multiple attempts to seek a stable solution using currently available data were made until DECC and the PTE were satisfied that the attempts could be considered exhaustive for all practical purposes.

115. The volume of expected energy unserved (EEU) was based on results from the Dynamic Dispatch Model (DDM). The first step involved selecting an appropriate scenario and then taking the product of the volume of EEU and the Value of Lost Load ("VoLL"), which yields the cost of the EEU to consumers. For simplicity, the model here uses a fixed number for VoLL. This, however, is a crude approach and we advocate running sensitivities on VoLL.

116. The capacity costs (and benefits) are calculated through considering how incremental calls on capacity affect clearing prices, which is determined by multiplying the change in the clearing price by the total capacity to procure, paid for in the Capacity Market (CM). This is represented by a linear capacity cost function derived from a regression on the cost curves for National Grid's four future energy scenarios (FES) and DECC's central scenario model runs.

117. The table below shows what costs and benefits are considered for under and over procurement situations.

Interconnector Procurement	GB Based Generation and / or Demand Side Resources	Interconnectors Deliver	Supply and Demand Balance and Expected Energy Unserved	Interconnector Rewards and Penalties
Procure low	Buy more GB generation (increases CM price)	Interconnectors deliver high	Increased supply lowers Expected Energy Unserved	Supply costs uprated by buying more GB generation (seen through Capacity Market price)
Procure high	Buy less GB generation (decreases CM price)	Interconnectors deliver low	Decreased supply raises Expected Energy Unserved	Supply costs reduced by buying less GB Generation

118. In this approach, the capacity costs impacts are much greater than the effect on unserved energy (even assuming VoLL a £17,000/MWh), however, this does not necessarily steer the LWR result towards a high DRF, since the LWR is driven by <u>differences</u> between minimums and maximums. This makes the LWR much less stable than in the comparable "target capacity" problem. It is thought this partly reflects the use of the linear supply curve. As a result of this, the model produces very

different LWR levels for small changes in input assumptions, and the direction of change is often counterintuitive. Interestingly, if one focuses on the average pay-off values, this approach clearly shows that selecting higher DRF yields the highest benefits (or least cost).

119. This last output aligns with our *a priori* expectation. Unfortunately, the main LWR modelling does not appear sufficiently robust that we can rely on it for the purposes of calculating the de-rating factors. It is possible that further analysis may yield a more robust approach that avoids the unexplained irregularities.

120. Applying a simple average (in this case the arithmetic mean) presents a straight forward mechanistic approach. It has two advantages:

- It is transparent and easy to explain;
- It represents a risk-neutral approach.

121. On the other hand a simple average has two main disadvantages:

- It is does not take into consideration any dimension relating to costs and benefits;
- It value will be influenced by the number and range of input estimates, such that changing the set of inputs moves the average.

122. On balance, the simple average provides a secondary fall back solution, should the LWR approaches yield no strong guide as whether to err on the low or high side.

123. Our third approach is to apply a qualitative LWR approach which considers the nature and magnitude of costs of setting the DRF for interconnection too high or too low. The costs are seen in terms of impacts on capacity market prices, energy (day ahead and intraday) and balancing prices and the corresponding response from various parties including generators, DSR providers and interconnector owners.

124. The main impacts of over and under procurement are summarised in the table below and expanded upon in the following paragraphs.

IC procurement	Domestic generation & DSR	S/D balance, EEU & energy prices	Interconnector flows	Optionality
Procure low DRF	Buy more GB generation & DSR (increase CM price)	Increased supply lowers EEU and energy prices	Imports fall	None available
Procure high DRF	Buy less GB generation & DSR (decrease CM price)	Decreased supply raises EEU and energy prices	Imports increase	Buy extra GB gen/DSR in T-1 (consider SO countermeasures)

125. First, we consider the **impact of setting the derating factor too high** in relation to the main parties affected:

The Interconnector Operator:

- will receive too much money but will also displace the need for GB generation and DSR thereby reducing auction clearing prices;
- would be expected to pay more in penalties.

Non-interconnector Capacity Market participants:

- will invest in less domestic generation (reducing costs to consumers in the generator Capacity Market) and a failure to secure capacity sufficient to meet the reliability standard (reducing costs to consumers) but would also increase prices in the Day Ahead Market, the Intra-day Market and the Balancing Market, all of which would incentivise investment in existing and new capacity as well as other actions that increase security of supply;
- Demand Side Resources may be squeezed out and will be less incentivised to supply smart innovation (which may either reduce or increase costs to consumers in the demand side CM depending on the relative cost of DSR and Generation);
- During later auctions, we might expect to see corrections (albeit that some of the opportunities currently available in an auction may disappear) and there would need to be more recognition of National Grid's existing countermeasures which are not included in the analysis to date as well as more focus on stimulating alternatives such as demand side resources.

126. Next we compare the **impact of setting the derating factor too low** in relation to the main parties affected.

The Interconnector Operator:

- will receive too little money (tending to reduce costs to consumers) but raising auction prices (tending to increase costs to consumers)
- would be expected to pay less in penalties

Other Capacity Market participants:

- more domestic generation capacity will be procured (increasing costs to consumers in the generator Capacity Market) AND / OR
- will come forward with too much Demand Side Resource (increasing costs to consumers in the demand side Capacity Market)
- will see too much generation or Demand Side Resource leading to suppression of price signals drawing flows into the UK at system stress. (Key to this is the evidence that market coupling significantly increases the correlation between flow and price). Lower wholesale and balancing prices will reduce incentives to be available (those holding capacity agreements will be able to trade if they are short at modest cost). Lower forecast wholesale and balancing prices will reduce expected generator revenue and require higher capacity auction prices to justify investment, and will fail DG COMP's requirement that the solution should be the least cost way of addressing the market failure (in this case, presumably of missing money).

127. There are further points that are noteworthy relating to the confidence to be placed in market coupling and the relative costs and benefits arising from keeping some procurement options open while knowledge of the market and alternative sources of supply security evolve both increase.

128. In relation to the confidence to be placed in Market Coupling, which should lead to an efficient market in the mutualisation of energy security that will benefit consumers, we note that the interconnectors were only included after the volumes for the 2014 Capacity Market had been announced. We noted above that DG COMP is likely to

exempt interventions like a capacity mechanism if they are the least cost ways of delivering security of supply. We note that the 2014 DECC Impact Assessment included interconnectors because market signals (balancing and market coupling) had sharpened allowing the market to play a more active role. We also note that flows over interconnectors and hence their contribution will be market-determined. Given all that it is hard to argue that the only reason for a failure to import at the technical derating factor in stress periods is a simultaneous stress event at each end, which will be primarily driven by weather and co-incidental plant outages, otherwise our markets should be signalling the stress event and importing. That would suggest using the weather / (temperature and wind) and simultaneous LoLP. Over-procurement that reduced the number and severity of stress events would undermine the market role and constitute inefficient state aid.

129. The PTE's review of the above impacts of erring on under- versus over-procurement of Interconnector DRFs suggests that it would be more rational to set a high DRF as this will provide stronger incentives for addressing the missing money problem and is more consistent with DG COMP's ambitions. In addition, the System Operator would retain a reasonable degree of flexibility to make final adjustments via the T-1 auction and other counter-measures. We note that our presumption of the relative benefits of high DRF's are supported by the expected values in the LWR pay-off matrix, which show high DRFs yield the highest benefits.

130. Following our suggestions above, we would also make the following recommendations:

Recommendation 14: Further work should be carried out to assess whether the LWR methodology can be used for selecting a single derating factor for each interconnected system.

Recommendation 15: In choosing derating factors in the present circumstances, the PTE believes that it is better to err on the higher side of any uncertainty taking into account at least the factors that have been suggested above.

Summary of New Recommendations

(The numbering of the recommendations follows on from those of our first report, discussed at 20 above).

In relation to the understanding of the potential contribution of DSR:

Recommendation 11: Additional analyses should be undertaken to understand the full, absolute potential of DSR in addition to its potential within current market arrangements so that future analyses can anticipate the contribution it may make.

In relation to the understanding of the value of lost load to consumers:

Recommendation 12: For future years, National Grid should expand its analysis of loss of load events to take account of the volume, frequency, duration, forewarning and predictability of loss of load events. In particular, National Grid may wish to describe in detail the full range of actions to manage loss of load and their time evolution. These might in future include public information broadcasts to avoid predictable stress events (as has worked successfully in relation to water shortages), the impact of smart technology designed to time-shift electrical load and encouraging DNOs to minimise the impact on consumers by more targeted, quarantined loss of load or disconnections when necessary. In the past the French electricity system, which is far more weather sensitive than the British system, has developed a variety of ways that give strong incentives to reduce load in announced stress situations, and lessons learned from those measures might also be valuable.

In relation to the ongoing improvements required for analysing the contributions of interconnectors to security of supply:

Recommendation 13: DECC and / or National Grid should encourage the earliest possible development of a pan-European dispatch model with the functionality to simulate the behaviour of interconnectors in a variety of market coupled scenarios. We recognise that intra-day and balancing markets are not yet properly coupled and would recommend that informed judgements about how they will be coupled should be modelled, as stress events are more likely to impact these markets.

In relation to the selection of interconnector derating factors:

> **Recommendation 14**: Further work should be carried out to assess whether the LWR methodology can be used for selecting a single derating factor for each interconnected system.

and

> **Recommendation 15**: In choosing derating factors in the present circumstances, the PTE believes that it is better to err on the higher side of any uncertainty taking into account at least the factors that have been suggested above.

Glossary

CfD	Contract for Difference
CM	Capacity Mechanism
CONE	Cost of New Entry
DNO	Distribution Network Owner
DRF	De-rating Factor, the ratio of the amount of reliable deliverability to the nominal or nameplate capacity or TEC, whichever is lower
DSR	Demand side response or resource
EEU	expected energy unserved
EMR	Electricity Market Reform, as set out in the Energy Act 2014
IA	Impact Assessment
ICRP	Investment Cost-Related Pricing (for setting grid charges)
IFA	The interconnector from France to England (Angleterre)
I-SEM	Integrated SEM (Redesigned SEM meeting requirements of EU Target Model)
LoLE	Loss of Load Expectation
LWR	Least Worst Regrets
PTE	Panel of Technical Experts
PV	(solar) photo-voltaic
SEM	Single Electricity Market of the island of Ireland
TA	Transitional Arrangements to help DSR to participate in the main Capacity Market
TEC	Transmission Entry Capacity – the amount on which a generator pays TNUoS
TNUoS	Transmission Network Use of System (of charges levied on Generators)
VoLL	Value of Lost Load