National Grid EMR Electricity Capacity Report

31 May 2017 (submitted to BEIS)

Report with results from work undertaken by National Grid for BEIS in order to support the development of Capacity Market volume to secure.

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National Grid EMR Electricity Capacity Report

1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling analysis undertaken by National Grid in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision by the Government on the amount of capacity to secure through the Capacity Market auctions for delivery in 2018/19 and 2021/22.

The Government requires National Grid to provide it with a recommendation for each year studied based on the analysis of a number of scenarios and sensitivities that will ensure its policy objectives are achieved in a cost effective manner.

National Grid has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2016 process and adjusted and improved this year's analysis appropriately to try to address their feedback. In addition there has been a series of workshops with BEIS (formerly DECC), PTE and Office of Gas and Electricity Markets (Ofgem) to enable them to scrutinise the modelling approach and assumptions utilised.

Chapter 2 of this report describes the modelling approach including the tools used and enhancements made for this year's analysis. Chapter 3 covers the scenarios and sensitivities modelled. Chapter 4 details the de-rating factors for generating technologies, DSR and interconnected countries. Chapter 5 contains results from the scenarios modelled and the recommended capacity to secure for the 2021/22 T-4 auction. Chapter 6 contains results from the scenarios modelled and the recommended capacity to secure for the 2018/19 T-1 auction. Finally the Annex contains the details behind the scenarios, demand & generation methodology and assumptions, the modelling approach, development projects, station availabilities, Reserve for Response and the quality assurance process.

1.1 Results and Recommendations

National Grid has modelled a range of capacity options based around meeting the Reliability Standard in different combinations of credible scenarios and sensitivities. The assumption is that the Future Energy Scenarios (FES) and the Base Case will cover uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), interconnection capacity and generation with the sensitivities covering uncertainty in non-delivery, station peak availabilities, weather, wind levels and peak demand forecast range (based on the Peak National Demand Forecasting Accuracy (DFA) Incentive[3]) plus interconnector flow sensitivities (for 2018/19 only).

Scenarios & Base Case

- Base Case (5 year forecast to 2021/22, then Steady State from 2022/23 onwards[4])
- FES Two Degrees (TD)
- FES Slow Progression (SP)
- FES Steady State (SS)
- FES Consumer Power (CP)

[1] https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts
[2] https://www.gov.uk/government/publications/electricity-market-reform-panel-of-technical-experts-2016-final-report-on-national-grids-electricity-capacity-report-2016
[3] See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf
[4] For most scenario components. Exceptions include interconnection

To provide the reference case which is being used to apply sensitivities, a Base Case has been introduced. For the DFA incentive years up to 2021/22, this consists of a forecast of demand and a generation background which aligns with our DFA Incentive and aims to reduce the likelihood of over or under securing of the capacity thereby minimising the associated costs to consumers.

While the FES scenarios vary many variables (see list of primary assumptions in Annex), the sensitivities vary only one variable at a time. Each of the sensitivities is considered credible and is evidence based i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. Section 3.10 describes each sensitivity and how it has been implemented.

The LWR methodology is explained in the Annex. As per previous ECR analysis, it uses a cost of capacity of £49/kW/yr (net CONE (Cost of New Entry CONE)) and an energy unserved cost of £17,000/MWh to select a scenario/sensitivity combination from which the recommended capacity to secure is derived. Note that the Government's Reliability Standard[5] was derived using a slightly different capacity cost of £47/kW/yr based on the gross Cost of New Entry (CONE) of an Open Cycle Gas Turbine (OCGT).

1.1.1 2021/22 T-4 Auction Recommendation

Results

The outcome of the LWR calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2021/22 of **50.5 GW** derived from the requirement of the Base Case 2000 MW non-delivery sensitivity. This does not take account of a different clearing price to net CONE resulting from the auction as our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation excludes any capacity secured in earlier auctions for 2021/22 that is assumed in the Base Case.

In general, when compared to the analysis for 2020/21 in the 2016 ECR, the 2017 ECR recommendation for 2021/22 is 0.8 GW higher. This is a result of a 1.1 GW increase in capacity requirement (mainly as a result of a higher assumed peak demand) offset by a slightly higher (0.3 GW) level of assumed CM-ineligible de-rated capacity at peak (caused by higher assumed levels of previously contracted capacity partly offset by lower levels of ineligible autogeneration[6] compared to the 2016 ECR). Chapter 5 contains further details on the comparison with the 2016 ECR.

The following waterfall chart shows how the original 49.7 GW requirement for the 2020/21 T-4 auction (derived from the 2016 Base Case 2000 MW non-delivery sensitivity) has changed into a recommended requirement of 50.5 GW (derived from the 2017 Base Case 2000 MW non-delivery sensitivity) as a result of the net increase described above.

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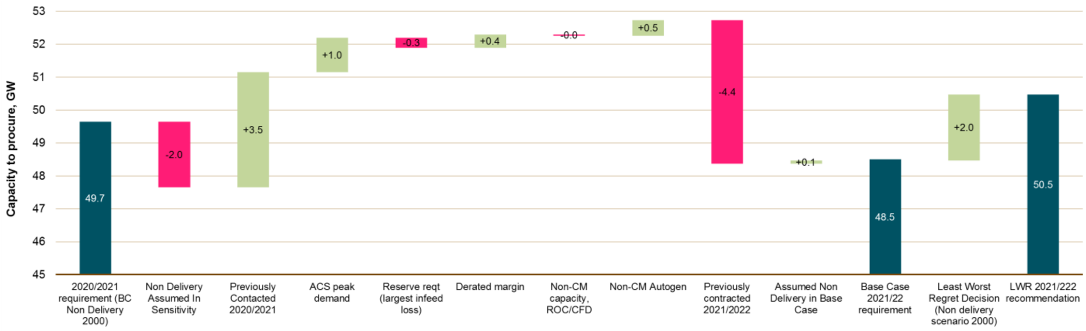
[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

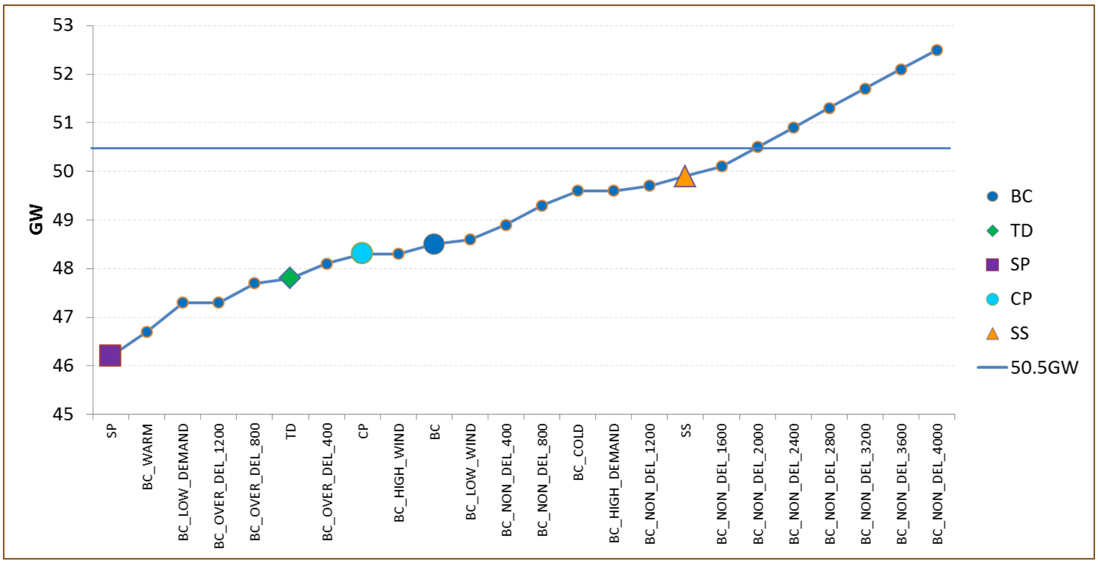
[6] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW.

Figure 1: Comparison with recommended 2020/21 T-4 requirement in 2016 ECR



The following chart illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity.

Figure 2: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2021/22



Recommendation

The recommended target capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the National Grid recommended capacity auction requirement, a number of adjustments to the total recommended figure may be required which are detailed in Chapter 5.

Therefore, the recommended total capacity to secure through the 2021/22 T-4 auction will be:

- 50.5 GW minus any adjustments

1.1.2 2018/19 T-1 Recommendation

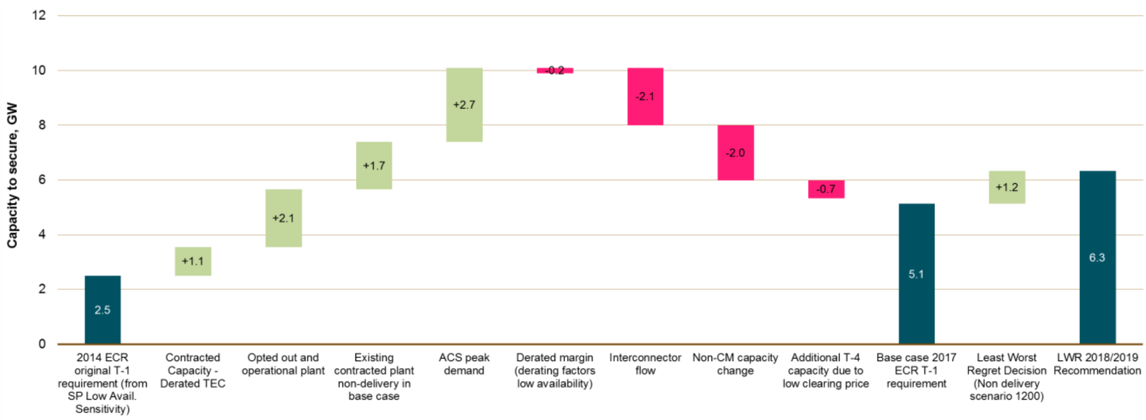
Results

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2018/19 of **6.3 GW** derived from the requirement of the Base Case 1200 MW non delivery sensitivity (see Chapter 6 for further details). This does not take account of a different clearing price to net CONE resulting from the auction as our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also excludes any capacity secured by the T-4 auction for 2018/19 that is assumed in the Base Case.

In general, when compared to the analysis for 2018/19 in the 2014 ECR that ultimately led to the 2.5 GW set aside by the Secretary of State for the T-1 auction, the 2017 ECR recommendation for 2018/19 is 3.8 GW higher than the 2.5 GW set aside. There is a 7.9 GW increase in capacity requirement resulting from higher peak demand, a reduction in assumed opted-out and operational capacity, known non-delivery, differences between contracted capacity and de-rated TEC and a wider range of sensitivities that increases the requirement in the LWR analysis. The increase is partly offset by a 4.1 GW increase in assumed ineligible capacity at peak due to higher assumed imports at peak, higher renewables contribution at peak and higher levels of assumed opted-out or ineligible (below 2 MW) autogeneration. Chapter 6 contains further details on the comparison.

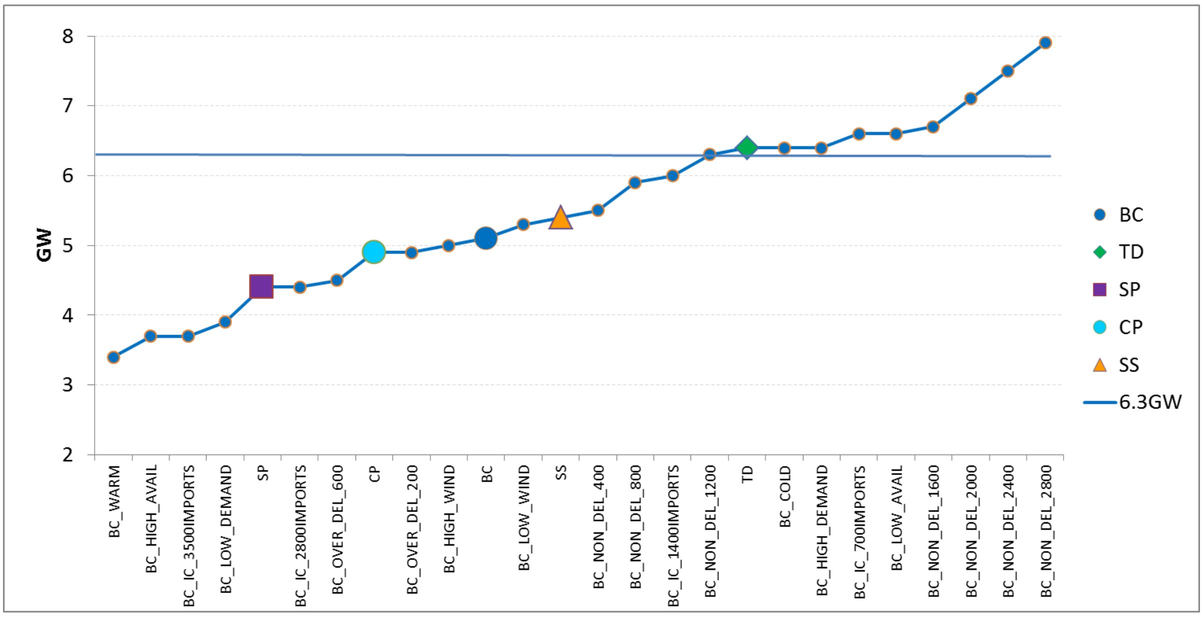
The following waterfall chart shows how the original 2.5 GW set aside for the 2018/19 T-1 auction (derived from the 2014 Slow Progression Low Availability sensitivity) has changed into a recommended requirement of 6.3 GW (derived from the 2017 Base Case 1200 MW non-delivery sensitivity) as a result of the net increase described above.

Figure 3: Comparison with original 2018/19 T-1 requirement (de-rated)



The following chart illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity. Note that National Grid's recommendation concentrates on the target capacity alone.

Figure 4: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2018/19



Recommendation

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the auction capacity requirement, a number of adjustments to the recommended figure may be required which are detailed in Chapter 6.

Therefore, the recommended total capacity to secure through the 2018/19 T-1 auction will be:

- 6.3 GW minus any adjustments

1.2 Interconnected Countries De-rating factor Ranges

Table 1: De-rating factor ranges shows the recommended ranges for de-rating factors in 2021/22 for all existing and potential interconnected countries. Note that there are no potential ranges for interconnector de-rating factors for 2018/19 as they are excluded from participating in the auctions for that delivery year.

These de-rating factors are based around the modelling we have done using Bid3, our new pan-European market model and Pöyry's analysis on historical performance. For all countries the top of the de-rating factor ranges are set by the pan-European modelling. For France, Netherlands and Belgium Pöyry's analysis of seven historical years[7] sets the bottom of the ranges. The bottom of the range for Norway is set to the lowest value from our pan-European modelling.

We have assumed that by 2021/22 the successful introduction of the Integrated Single Electricity Market for the island of Ireland (I-SEM) could fundamentally change the Irish market meaning the historical market data analysed by Pöyry may no longer

[7] See schedule 3A of the CM rules. https://www.gov.uk/government/publications/capacity-market-rules

be valid. Therefore we have used the lower Irish capacity margin sensitivity to set the lower bound. This is based on the recent All-Island Generation Capacity Statement[8] which suggests that margins in Ireland will narrow by the mid-2020s because the new Irish capacity market will only support generation to meet the Irish security standard.

The assumption of successful market changes in Ireland is not certain and if market coupling does not develop in Ireland then the Pöyry history may be a more appropriate lower bound. Due to the uncertainties of how the Irish market will develop and to ensure a smooth transition we suggest a de-rating factor towards the lower end of the range would be appropriate. This year our Irish range does not include an allowance for the impact of network constraints on the assumption that this is more appropriately allowed for in the adjustments BEIS make to individual interconnector de-rating factors along with technical availability.

Table 1: Recommended de-rating factor ranges

%'s		France	Netherlands	Ireland	Belgium	Norway
2021/22	High	80	81	98	85	99
2021/22	Low	48	75	29	65	92

1.3 National Grid Analysis Delivery Timeline 2017

The process and modelling analysis has been undertaken by National Grid with ongoing discussions with BEIS, Ofgem and BEIS's PTE during the development, modelling and result phases.

The work was carried out between September 2016 and May 2017 and builds on the analysis that was undertaken for the previous ECRs. In addition to the analysis around the recommended capacity to secure, the report also presents analysis on the de-rating factors for interconnectors and conventional plants for use in the auctions.

The following timeline illustrates the key milestones over the different modelling phases of the work to the publication of the ECR:

- Development plan produced in September 2016
- Development projects phase October to February 2017
- Production plan developed in February 2017
- Modelling analysis March to May 2017
- National Grid's ECR is sent to BEIS before 1st June 2017
- Publication of ECR in line with BEIS publishing auction parameters in early July 2017

[8] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

2. The Modelling Approach

The modelling analysis has been undertaken by National Grid with ongoing discussions with BEIS, Ofgem and BEIS's PTE throughout the whole process.

2.1 High Level Approach

The modelling approach is guided by the policy backdrop, in particular the objectives set by Government regarding security of supply. The modelling looks to address the following specific question:

What is the volume of capacity to secure that will be required to meet the security of supply reliability standard of 3 hours Loss of Load Expectation (LOLE)[9]?

In order to answer this question it was agreed, following consultation with BEIS and their PTE, that the Dynamic Dispatch Model (DDM)[10] was an appropriate modelling tool. This maintains consistency with the energy market modelling work undertaken by BEIS. The DDM has the functionality to model the Capacity Market with the Annex describing the modelling in more detail. It should also be noted that when compared to National Grid's capacity assessment model, developed to support Ofgem's Electricity security of supply report[11], the DDM has been shown to produce the same results, given the same inputs.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[12], and sensitivities around a Base Case which cover a credible and broad range of possible futures. See Chapter 3 for details of the scenarios and sensitivities used in the modelling.

The scenarios are comprised of assumptions around:

- Peak demand – Prior to any demand side response
- Generation capacity – Both transmission connected and distributed (within the distribution networks)
- Interconnector assumptions – Capacity assumptions (note that flows at peak are modelled directly within DDM except for 2018/19)

Sensitivities are then created around the Base Case to ensure consistency with National Grid's Peak National Demand Forecasting Accuracy (DFA) Incentive[13].

Separate model runs were carried out for years 2018/19 and 2021/22 as the treatment of interconnectors, levels of previous contracted capacity and sensitivities applied to each of these years were different. For 2018/19 interconnectors cannot participate in the auctions so an allowance is made off line based on our own Pan-European modelling and de-rating factors from previous auctions.

[9] LOLE is the expected number of hours when demand is higher than available generation during the year but before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

[10] DDM Release 5.0.17.1 was used for this analysis

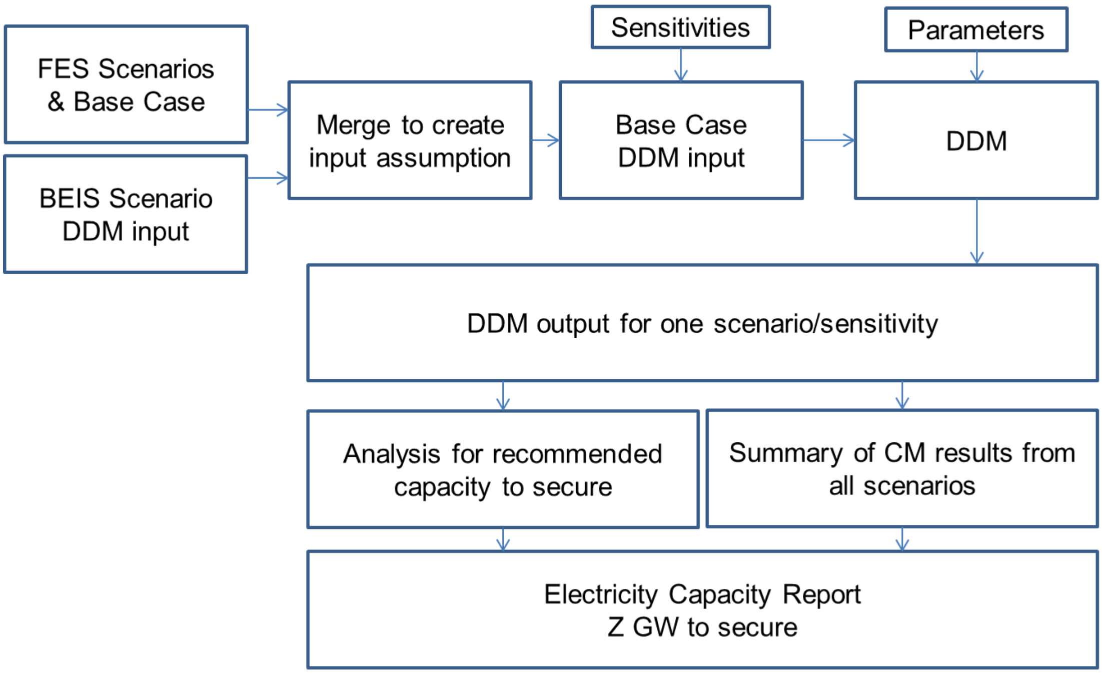
[11] https://www.ofgem.gov.uk/sites/default/files/docs/2015/07/electricitysecurityofsupplyreport_final_0.pdf

[12] http://fes.nationalgrid.com/

[13] See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

The modelling process, detailed below, determines a capacity to secure and provides a view of capacity which is expected to be delivered outside of the Capacity Market. Each of the scenarios and sensitivities produces a capacity to secure for those given circumstances and these are considered together to produce a recommended capacity to secure in the Capacity Auctions for 2018/19 and 2021/22. This process is detailed in the Annex.

Figure 5: Process flow chart of approach to calculate target capacity to secure from individual scenario/sensitivity runs



2.2 DDM Outputs Used in the ECR

For the purpose of the ECR, the key outputs utilised from the DDM for each year modelled from 2018/19 to 2031/32 are the aggregate capacity values, specifically:

A. Total de-rated capacity required to hit 3 hours LOLE
B. De-rated capacity to secure in the Capacity Market auction
C. De-rated non-eligible capacity expected to be delivered outside the Capacity Market auction
D. Total nameplate capacity split by CM and non-CM eligible technologies.
E. De-rated capacity already contracted for, from previous auctions (part of C)

Note that A = B + C. Further details on the modelling and aggregate capacities can be found in Annex.

In addition to the aggregate capacity values, for the purpose of calculating the recommended capacity to secure in 2018/19 and 2021/22, the ECR also utilises the expected energy unserved (EEU) values for potential de-rated capacity levels in both years (see Chapters 5 & 6 for more details).

No other outputs from the DDM are utilised directly in the ECR.

2.3 Stakeholder Engagement

National Grid has a well-established and extensive consultation process which is followed on an annual basis to create the Future Energy Scenarios (FES). The process incorporates webinars, workshops and bilateral meetings with our stakeholders to ensure we are receiving up to date information and feedback for our scenarios. The content of the FES is driven by stakeholder feedback; this results in a range of holistic, credible and plausible scenarios. We publish the outputs of our consultation process each year in the FES Stakeholder Feedback document[14] in line with our licence condition. The document, published annually in February, shows how stakeholder feedback influences the scenario format and the content of the model inputs that underpin the scenarios. This document contains details of the questions that we ask our stakeholders and the range of their responses.

National Grid strives to improve the FES consultation process each year by enhancing engagement activities and finding better ways to record and analyse stakeholder feedback. National Grid also engages with stakeholders to explain its role in relation to EMR through the CM Implementation workshops and at meetings with trade organisations and individual companies as part of our ongoing consultation around the EMR work in general but in particular the de-rating factors we recommend to BEIS for use in the auctions.

2.4 High Level Assumptions

There are numerous assumptions which are required for the modelling process.

2.4.1 Demand & Generation

The starting point for the DDM input modelling assumptions was the set of assumptions used in the latest BEIS modelling e.g. assumptions behind generation levelised costs. However, the key inputs/assumptions are taken by aligning the modelling to the new 2017 FES scenarios and agreed sensitivities. The key assumptions are those that materially affect the capacity to secure, these are:

- Demand Forecasts
  - Peak demand
  - Annual demand forecasts
- Generation Capacity
  - Capacity eligible for the Capacity Market
  - Capacity outside the Capacity Market (including capacity secured via previous auctions)

For a detailed breakdown of these key input assumptions see the Annex.

2.4.2 Interconnector Assumptions

Whilst interconnectors are not allowed to participate in the T-1 auction for 2018/19, they are eligible to participate in the T-4 auction for 2021/22. This has resulted in an approach to modelling interconnectors where instead of estimating potential flows via scenarios and sensitivities as for 2018/19, these will now be determined by

[14] http://fes.nationalgrid.com/media/1195/stakeholder-feedback-document-fes-2017.pdf

probabilistic modelling in a similar way to generation technologies i.e. based around a set of flow distributions obtained from our own pan European electricity dispatch market modelling using Bid3[15] (see 2.4.3.3 for further details).

In addition to this modelling work, National Grid will provide a recommendation on the potential range of de-rating factors to apply for each connected country participating in the CM auction. See Chapter 4 for more detail around this process and the recommended de-rating factors.

2.4.3 Station Availabilities

This analysis has been split into three sections; firstly for conventional generation, secondly intermittent generation and then finally interconnectors.

2.4.3.1 Conventional generation

Conventional generation capacity is not assumed to be available to generate 100% of the time, due to break downs and maintenance cycles. In order to determine what availability to assume for each generation type, National Grid considers what has been delivered historically, based on the average on high demand days over the last seven winter periods[16]. This approach has been used by National Grid in its entire medium to long term modelling, as well as being used for the EMR Delivery Plan and Ofgem's Capacity Assessment. This methodology is described in detail in Annex 7.2 of the 2014 ECR[17].

Table 2 shows the station availabilities based on the last 7 winters (2010/11 – 2016/17) for each type of generation. The availability is defined as the mean of each of the last 7 winter's availability values.

Table 2: Station Availabilities

Generation Type	
CCGT	89%
OCGT	95%
Coal	88%
Nuclear	85%
Hydro	88%
Pumped Storage	96%

Previous comments[18] from BEIS's PTE stated that the availability of CCGT plant was low when compared to other markets with similar support mechanisms and recommended that National Grid undertake analysis to benchmark CCGT and other technology availabilities from around the world.

Previously, National Grid commissioned ARUP, in 2014, to produce a report on the availability of plant, particularly CCGTs, in markets that incentivise availability. For the main generation technologies of CCGT, OCGT, coal and nuclear, Arup provided an availability assumption. The following table shows the two views of availabilities.

[15] http://www.poyry.com/BID3
[16] Specifically these periods are 0700-1900 Mon-Fri, Dec-Feb (inclusive) on days with a peak demand greater than the 50th percentile (90th percentile for CCGTs) of demand for that winter
[17] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34154
[18] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267624/Annex_E_-_PTE_draft_report_FINAL.pdf

Table 3: Availability Comparison

Generation Type	National Grid	Arup
CCGT	89%	87% -93%
OCGT	95%	94%
Coal	88%	87%
Nuclear (Existing)	85%	77%

Based on the international benchmark data provided in Arup's report and further discussions with BEIS and the PTE, the availabilities for each type of generation have been revised to the following values:

Table 4: Availabilities Used

Generation Type	Availability %
CCGT Pre 2020/21	89%
CCGT 2020/21	90%
CCGT Post 2020/21	90%
OCGT	95%
Coal	88%
Nuclear (Existing)	85%

Given the historical plant economics, age and mode of operation it is not surprising that GB CCGT availabilities were at the lower end of the international range. However, availabilities have been marginally increasing over the last couple of years reflecting the improved economics of plant and increased maintenance. This supports what we assumed would happen over the last few ECRs with availabilities rising to 90% by 2020/21.

National Grid has used the above approach to determine station availabilities for the last few years. While informal consultations on the approach have been conducted through discussions at industry forums and bilateral meetings it is important that all stakeholders have an opportunity to engage in this process. This will help National Grid understand any concerns that stakeholders may have regarding this approach and help to inform any future changes to the methodology. Therefore, National Grid continues to welcome comments and questions on this approach either through email (emr@nationalgrid.com), industry forums or bilateral meetings.

2.4.3.2 Wind generation

Intermittent renewable plants run whenever they are able to, and so the availability of the fuel source is the most significant factor. When considering these plants, National Grid looks to their expected contribution to security of supply over the entire winter period. For wind, this is achieved by considering a history of wind speeds observed across GB, feeding in to technology power curves, and running a number of simulations to determine its expected contribution. This concept is referred to as Equivalent Firm Capacity (EFC). In effect, it is the level of 100% reliable (firm) plant that could replace the entire wind fleet and contribute the same to security of supply. The wind EFC depends on many factors that affect the distribution of available wind generation. These include: the amount of wind capacity installed on the system; where it's located around the country; and the amount of wind generation that might be expected at periods of high demand. It also depends on how tight the overall system is e.g. as the system gets tighter, the wind EFC increases for the same level of installed capacity as there are more periods when wind generation is needed to meet demand rather than displacing other types of generation in the merit order. It should be noted that the EFC is not an assumption of wind output at peak times and consequently should not be considered as such.

2.4.3.3 Interconnectors

In the DDM, for years apart from 2018/19, we have modelled the contribution of interconnectors at peak times by assigning a probabilistic distribution to each interconnector, defining the probability of each import / export level for a given level of net system margin. These distributions were derived from our own pan–European market modelling (see Chapter 4). The DDM calculated an EFC for interconnection which was used as an estimate of the aggregate interconnector de-rated capacity. Note that the modelled de-rating factor for interconnection has no impact on the total de-rated capacity (including interconnection), required to meet the Reliability Standard. In the auction, interconnection capacity will compete with other types of new/existing eligible capacity to meet the capacity requirement.

2.4.3.4 Impact of availability assumptions

Given that the recommended capacity to secure is a de-rated value, the assumptions around availability of both conventional and renewable capacity have limited impact on the recommendation. Broadly the same level of de-rated capacity is required to hit the 3 hours LOLE; however, the name-plate capacity required to achieve that level of de-rated capacity will be slightly different. See Chapter 6 for the details of how de-rated capacity changes with variations in availability assumptions in 2018/19.

2.5 Development projects

The development project phase of the ECR was planned between October 2016 and the end of February 2017 and during this period a series of projects to potentially enhance the modelling process were undertaken. As part of this process we worked closely with BEIS and Ofgem to determine which projects to prioritise and then worked collaboratively and with consultants to deliver against the plan.

2.5.1 Process for selecting which development projects to progress

A key element of this process are the recommendations from BEIS' PTE who identify a number areas of research to be progressed which when combined with National Grid, BEIS and Ofgem's ideas produce a long list of potential projects, far more than can be undertaken (see Annex). Consequently, a method of prioritisation is required to determine which projects go ahead.

This is achieved by agreeing criteria around impact, effort and priority and then National Grid, BEIS and Ofgem score each project independently which enables the projects to be ranked. This ranked list is then matched to a high level resource plan to determine how many of the projects can be considered. Project scopes are then developed to flesh out the detail of how and what will be delivered and then matched again against the resource plan to develop a detailed development project plan with delivery timelines identified and agreed.

Clearly flexibility has to be incorporated in the process to deal with unforeseen issues. This is done by agreeing a change control process that allows for new projects to be considered and if important enough replace one of the existing planned projects to ensure delivery can still be met with the resources available. This change control process was implemented a couple of times during the development phase.

2.5.2 Key projects undertaken

The Annex contains a list of all the development projects considered and which ones were progressed and why based on their relative scores.

This year's key development projects related to:

- Investigating the possibility of using probabilistic weightings within the LWR decision tool and in particular for certain non-delivery sensitivities (PTE recommendations 17 & 25). To support this work we commissioned academic consultants from Heriot Watt University and Edinburgh University (Zachary, Wilson & Dent) to carry out research on whether any scientific approach could be adopted to calculate probabilities for sensitivities, including non-delivery sensitivities, and whether more extreme sensitivities (as utilised in other countries around the world in their security of supply analysis) could be included in a "hybrid" Least Worst Regret (LWR) model. Our own research on assigning probabilities concluded there was no sound methodology that could determine probabilities without making informed but nevertheless guesses which was subsequently supported by the academic work. In addition the hybrid approach investigated by our consultants (details of which can be found in the Annex) while showing promise required the inclusion of low probability events to make any material impact and it was thus agreed not to progress this without further research.
- 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.
- Development of in-house pan-European modelling of interconnector flows (PTE recommendation 13). Previously we had successfully commissioned Baringa to deliver analysis of interconnector flows that supported the 2015 and 2016 ECRs. As part of the System Operator's new Integrated Transmission Planning Regulation (ITPR) obligation we are required to set up in-house modelling that enables greater flexibility in modelling alternative scenarios and sensitivities across Europe along with planning and delivering the onshore, offshore and cross-border electricity transmission networks in a coordinated, economic and efficient manner into the long term. This was

achieved with the procurement of Pöyry's Bid3 pan-European model which has been run to support our EMR analysis work.

- Development of sensitivities around policy risk resulting in either increasing or decreasing potential for non-delivery (PTE recommendation 21). Previously non-delivery sensitivities were dominated by the risk around coal closures given their challenging economic situation and environment legislation. However, this non-delivery would be limited due to a market response from other generators benefiting from higher wholesale prices. In addition to this a new policy risk has come along in the shape of "embedded benefits" review which has the potential to result in the non-delivery of many small scale generators with several industry commentators suggesting up to 2GW was at risk (from the 2014 and 2015 auctions). We carried out our own analysis of the potential impact of removing embedded benefits (i.e. triad payments) from small scale generators and concluded the risk was uncertain and very dependent on the Internal rate of Return (IRR) assumptions made. This uncertainty led to a wide range of potential non-delivery but following discussion with BEIS, Ofgem and the PTE we decided to include up to 0.8GW of distributed capacity in non-delivery sensitivities for the 2021/22 T-4 auction. The final element of non-delivery risk related to unproven DSR contracted capacity where testing for the 2016/17 Transitional Arrangements (TA) showed approximately a third of capacity failed to deliver. However, over time we have assumed DSR participants would improve this performance but would not remove the risk all together.

2.5.3 Projects to be developed over the summer

There was one development project that was not possible to progress due to a combination of shortage of available resource and the required functionality not being present in current models so consequently it was deferred until the summer. It relates to the calculation of more appropriate de-rating factors for limited duration storage technologies.

- The market for battery storage is growing fast with many having won Enhanced Frequency Response (EFR) ancillary service contracts and CM contracts for 2020/21. Currently the rules mean that the closest transmission technology de-rating factor has to be applied for battery storage which is pumped storage; however, while pumped storage is available for a duration of 5+ hours, batteries are not, with most having around 30 minutes duration. Clearly with the estimated mean length of a "loss of load" event being around 2 hours, assuming a 30 minute battery can deliver for 2 hours is not appropriate. Thus more appropriate de-rating factors need to be calculated to ensure security of supply is appropriately modelled. This very issue was raised by a number of respondents to Ofgem's consultation on CM rule changes. Consequently, we have agreed with Ofgem and BEIS a project for the summer period that will calculate appropriate de-rating factors for different energy limited storage technologies of different lengths.

2.6 Modelling Enhancements since Last Report

Section 2.5 describes a number of development projects carried out in response to BEIS, Ofgem and National Grid's ideas along with the recommendations from the PTE. These developments have not led to any material changes to DDM functionality so any enhancements utilised for the 2017 ECR have related to updating data streams and good housekeeping. However, to support the summer project on storage de-rating, a development of the Unserved Energy Model (UEM) code within the DDM will be required which will be commissioned in June.

2.7 Quality Assurance

When undertaking any analysis, National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid has previously worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process.

The QA checks below are focussed on the points in the process where data is transferred from one model, or system, to another, together with the model outputs. These are:

1. **Interconnector flows** – Check the interconnector flow distribution
2. **Scenario inputs** – Check the model input assumptions
3. **Parameter Inputs / CM Results/ Historic Demand inc. distributed wind** – Check the model setup assumptions
4. **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model
5. **DDM Outputs** - Check model outputs are consistent with inputs and scenario criteria
6. **Capacity to Secure Process** – Check the inputs and outputs used to determine a range and recommended capacity to secure

The PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Internally the process has governance under Director UK System Operation. National Grid has also worked closely with LCP[19]) to check and verify the results obtained as part this analysis to reinforce the robustness of the QA process. For details of the QA undertaken by National Grid see the Annex.

[19] Lane, Clark and Peacock LLP – see http://www.lcp.uk.com/

3. Scenarios & Sensitivities

3.1 Overview

National Grid has a well-established and extensive consultation process on issues related to demand, generation and security of energy supply. This involves a continuous stakeholder consultation process with industry workshops, a summer seminar and bilateral meetings. As part of this process, a range of documents are published that are used as catalysts for feedback, they are:

- Future Energy Scenarios Stakeholder Engagement| National Grid
- Future Energy Scenarios | National Grid[20]
- Electricity Ten Year Statement | National Grid
- Gas Ten Year Statement | National Grid

This process results in the development of the Future Energy Scenarios (FES), derived using the latest information available on sources of supply and demand for both electricity and gas. The latest market intelligence is used to create the scenarios; for example, including the Transmission Entry Capacity (TEC) changes announced in March 2017, which are indications to National Grid that power plants have decided to reduce or increase the power that they will supply to the market.

For the 2017 FES, there are four scenarios based on the trilemma of supply security, affordability and sustainability. Security of supply for all scenarios is assumed not to exceed 3 hours LOLE, which leaves a 2x2 matrix to create the four scenarios. As such our 2017 scenarios are once again an evolution from the previous year. We have continued to use the 2x2 matrix (with axes of Green ambition and Prosperity) approach to structure our scenarios. We have also:

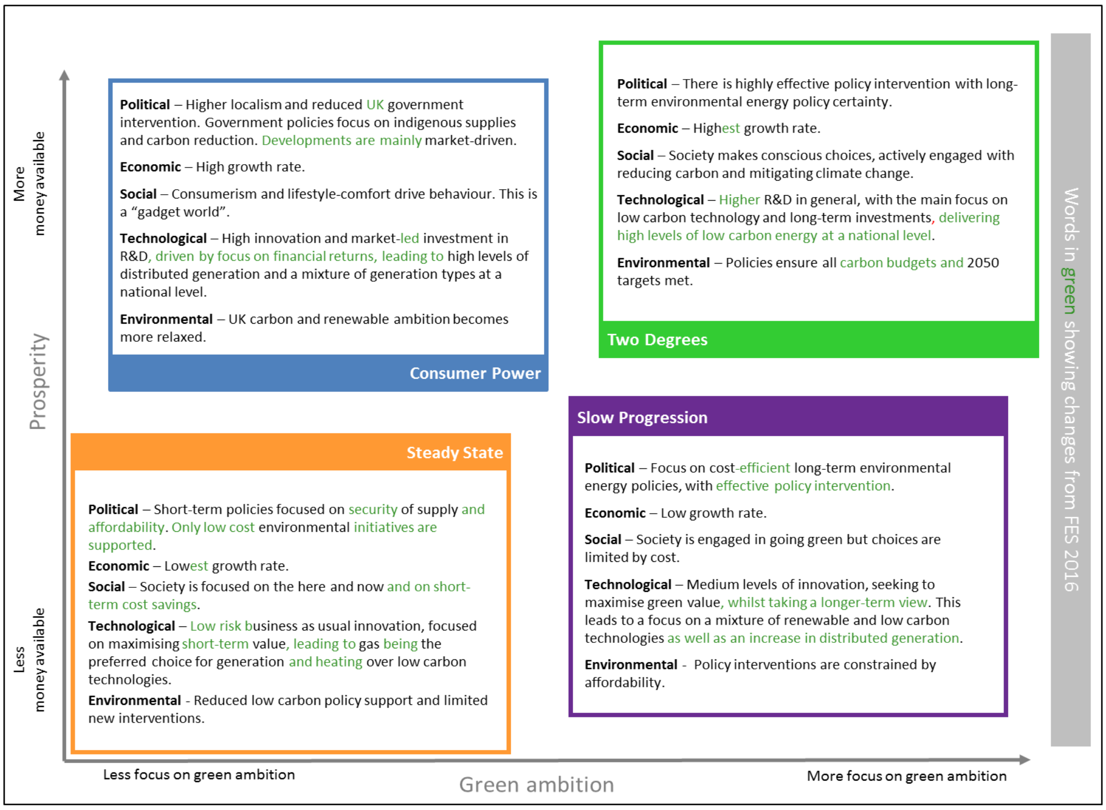
Repositioning the scenarios on the axes: We have repositioned the scenarios on the axes (see Figure 6). This reflects how we have distributed the wider range of economic growth forecasts across the four scenarios (i.e. Two Degrees being more prosperous than Consumer Power and Slow Progression being more prosperous than Steady State). The repositioning also reflects differences between the scenarios in the level of green ambition.

Retired the names 'Gone Green' and 'No Progression': These names have been retired to more accurately reflect the scenarios. The name Gone Green has remained the same since the scenario was first introduced in 2011, but the scenario itself has evolved significantly over the years. There has been a shift from a focus on renewable technologies to low carbon technologies, and in FES 2016 the scenario no longer met the 2020 renewables target (whilst still meeting the 2050 carbon reduction target). The name Gone Green is replaced by 'Two Degrees' and the scenario will continue to be our core scenario that meets the 2050 carbon reduction target (none of the other core scenarios will meet this target without further intervention). The name Two Degrees signifies that the scenario is consistent with the UK carbon budgets and the 2050 target which is the UK's contribution to the Paris Agreement of seeking to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels. Our stakeholders have told us they do not think the name No Progression accurately reflects the scenario. The name could suggest 'no

[20] Note that the 2017 document will be published on 13th July 2017

change', despite there being some business as usual progress and innovation. The new name, 'Steady State', better reflects the scenario which continues to represent a world where current levels of progress and innovation are reflected out to 2050.

Figure 6: Future Energy Scenarios Matrix



Given the wide range of applications that the scenarios are already used for, by both National Grid and the wider industry, the logical decision would be to use them for the Capacity Market analysis. In order to make further allowance for uncertainty in the coming years, the modelling has used a wide range of additional sensitivities.

For the purposes of modelling scenarios for the Capacity Market BEIS's DDM model has been used, as described in the Annex. Thus while the non-Capacity Market technologies are fixed to the levels assumed in each of the FES scenarios, DDM calculates Capacity Market (CM) qualified capacity to ensure that the 3 hours LOLE Reliability Standard is met. Hence the capacities shown in this analysis may diverge from those in the original FES scenarios which reflect what has actually happened in the market post auctions incorporating any potential for over delivery rather than the theoretical recommended target capacity.

Base Case

In addition to the four FES scenarios and to be compliant with our DFA Incentive we have used a Base Case from which all the sensitivities will be run from. This Base Case follows exactly the same principles using the same modelling approach as the FES scenarios to give a 5 year demand and generation background that is within the four FES scenarios range. Due to the inherent uncertainty across the market beyond 2021/22 the Base Case then follows the FES scenario that is closest to its DFA Incentive demand level in 2021/22 thereafter, which for the 2017 FES is the Steady State scenario.

The Base Case takes account of capacity market units awarded contracts in the previous 2018/19 T-4 auction that are now known not to be able to honour their contracts. It assumes that other capacity contracted in previous auctions is able to honour contracts over the next five years, with the exception of around 100 MW of small scale distribution connected capacity in the latter years of the five year period.

3.2 Scenario Descriptions

Descriptions of the four FES scenarios (for GB) are detailed below with a high level summary of the resulting capacity technology split between CM and non-CM plant following the DDM runs shown in the Annex. While DDM generates the final capacity figures required to meet the Reliability Standard for each scenario and sensitivity the FES scenarios are key inputs in determining the capacity to secure as they set the level of non-CM capacity which DDM then works around which explains the need to describe the assumptions behind each scenario.

3.2.1 Two Degrees

Two Degrees has the highest level of prosperity. Increased investment ensures the delivery of high levels of low carbon energy. Consumers make conscious choices to be greener and can afford technology to support it. With highly effective policy interventions in place, all UK carbon reduction targets are achieved.

Landscape

We see the highest economic growth of all the scenarios. There is a collective ambition to decarbonise the economy. High taxes are levied on those who continue to use carbon intensive options, such as conventional gas for heating. Policy and incentives are in place to reduce demand and increase renewable generation. This ensures progression towards the long-term green ambition.

Society is very conscious of its carbon footprint and is actively trying to reduce carbon emissions. Consumer demand for new green technologies is high and they are happy to spend money on home energy management systems, low carbon heating and insulation. There is also a drive to make low carbon transport greener.

Technology and investment are focused on low carbon generation, with the highest levels from sources such as solar, wind and nuclear generation. Investment in gas innovation continues as we look to produce more biomethane as well as other green gases.

3.2.2 Slow Progression

In Slow Progression low economic growth and affordability compete with the desire to become greener and decrease carbon emissions. With limited money available, the focus is on cost-efficient longer term environmental policies. Effective policy intervention leads to a mixture of renewable and low carbon technologies and high levels of distributed generation.

Landscape

Economically, conditions for growth are slow and gas prices rise significantly as a result of additional taxes. With limited money available to spend and invest, there is a focus on cost efficient long-term policies. Progress is made towards a low carbon world as government support and incentives are in place to grow renewable and low carbon technologies. This can be seen by the evolution in distributed generation.

Although we see an increase in these technologies the lack of money available reduces the pace of their adoption.

Businesses are more aware of their carbon emissions and are prepared to spend more on low carbon investments than cheaper less green options. Consumers are more proactive in engaging in an environmentally conscious way of life, but are limited in their choices by having less disposable income. They want to replace boilers and appliances to reduce emissions and be more efficient, but are more concerned with trying to keep costs down in a less prosperous world.

3.2.3 Steady State

In Steady State business as usual prevails and the focus is on ensuring security of supply at a low cost for consumers. This is the least affluent of the scenarios and the least green. There is little money or appetite for investing in long-term low carbon technologies. Therefore innovation slows which means the 2050 carbon reduction targets are not met on time.

Landscape

Steady State sees the slowest economic growth and subsequently there is the least investment in the longer-term future.

There is little ambition to move to a low carbon world, with policies that focus on the affordability of energy. No taxes are levied on the use of gas. There is limited intervention to encourage consumers to move towards greener sources of energy, as current technologies are favoured. Electricity prices are relatively low as subsidies for alternate low carbon sources are limited. The emphasis remains on ensuring security of supply at the lowest cost.

Consumers are very cost conscious and try to limit their spending and reduce their bills. With limited disposable incomes they are not tempted to buy expensive heating technologies or the latest gadget. They have no desire to move to a low carbon world.

Innovation continues as it does today. Businesses and consumers take a low risk, short-term value approach.

3.2.4 Consumer Power

In a Consumer Power world there is high economic growth and more money available to spend. Consumers have little inclination to become environmentally friendly. Their behaviour and appetite for the latest gadgets is what drives innovation and technological advancements. Market led investments mean spending is focussed on sources of smaller generation that produce short to medium term financial returns.

Landscape

Consumer Power has high economic growth, this means that society enjoys high levels of prosperity and has a high disposable income.

Government policies focus on indigenous energy supplies so in this world there is support for North Sea gas and the development of shale gas. Consumers and businesses benefit from low gas prices, it is cheap for them to use and they are not concerned with the cost or environmental impact of retaining high home temperatures.

There are fewer support mechanisms in place for renewable generation. Decisions are made at local levels as there are limited central government interventions and incentives.

Purchases of new and replacement residential appliances are high and, with the advances in technology, most will be smart and more energy efficient. As appliances tend to be larger and more are being bought, the energy savings are cancelled out by consumer demand. There is high uptake of electric and hybrid vehicles as desire increases for new and prestigious products.

3.3 Demand Forecast until 2021/22

The Base Case utilises a demand forecast covering the five year period 2017/18 to 2021/22. It supports the DFA Incentive which is instrumental in recommending a capacity to secure. This forecast is based on a central economic view, current energy policies, limited consumer behaviour change and the uptake of new technologies - such as electric vehicles and heat pumps. The following chart shows the Base Case peak demand forecast together with the projections for the FES over the five year period as well as the historic peak demands since 2011/12.

Figure 7 Peak Demand: FES Scenarios and Base Case to 2021/22

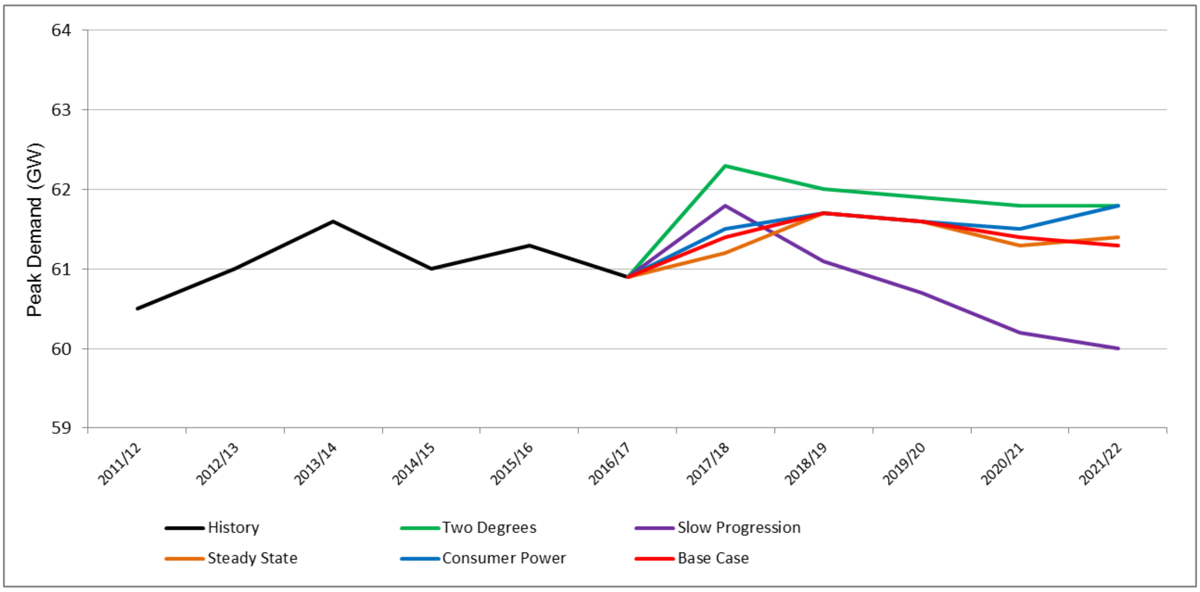


Table 5: Peak Demand to 2021/22

Peak Demand GW	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Two Degrees	60.9	62.3	62.0	61.9	61.8	61.8
Slow Progression	60.9	61.8	61.1	60.7	60.2	60.0
Steady State	60.9	61.2	61.7	61.6	61.3	61.4
Consumer Power	60.9	61.5	61.7	61.6	61.5	61.8
Base Case	60.9	61.4	61.7	61.6	61.4	61.3

In the short term demands are uncertain due to factors such as the 2017 general election, the eventual Brexit implications and potential changes in the direction of UK energy policy. We have illustrated this uncertainty by using a wider range of economic scenarios, which mainly affects industrial and commercial demand; these were derived using growth forecasts provided by Oxford Economics in December 2016. In the medium term, demands are projected to decline slowly due to improving energy efficiency, offset by growth in the economy and housing number increases. From 2018/19 onwards, Slow Progression has the lowest peak demand in the FES as the scenario has relatively high energy efficiency and relatively low economic growth.

3.4 Demand Forecast 2022/23 onwards

Each of the FES scenarios has its own annual demand projection; these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios.

Each of the FES scenarios has its own peak demand projection; again, these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios. The definition of peak demand used in the modelling is Unrestricted GB National Demand[21] plus demand supplied by distributed generation. Reserve required to cover for the single largest infeed loss is not included in the demand definition but is included in the modelling.

Demand is based on the Average Cold Spell[22] (ACS) peak demand and is consistently applied within the sensitivities based on the Base Case. The only adjustments to ACS peak demand are within the high and low demand sensitivities. All forms of DSR greater than 2 MW are eligible for the Capacity Market. This can include DSR through the use of an aggregation service. Note that this includes DSR at times of Triad charging periods. Therefore unrestricted peak demand is modelled i.e. no DSR or Triad avoidance has been subtracted.

See the Annex for details on the demand assumptions used in the FES scenarios and section 3.8 for more details on DSR. The following chart shows the peak demands (unrestricted end consumer demand plus losses but excluding exports and station demand).

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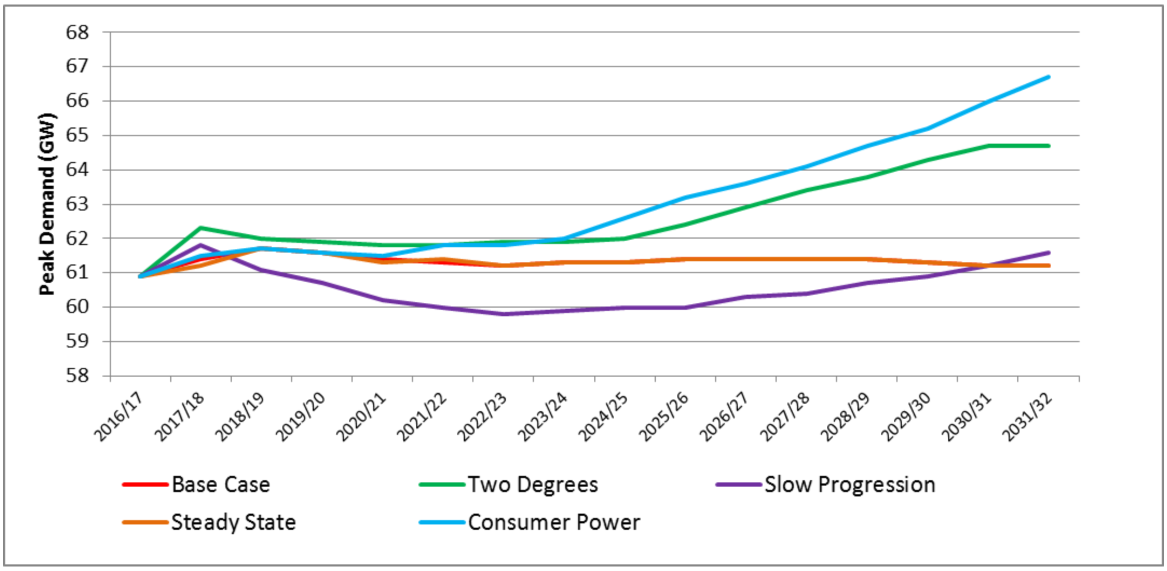
[21] National demand is defined in the Grid Code Glossary and Definitions http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/

[22] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

Figure 8 Peak Demand: FES and Base Case to 2031/32



3.5 Generation Capacity until 2021/22

Our generation capacity forecast from 2017/18 to 2021/22 is based on the latest market intelligence and an economic assessment and provides a potential view of the generation background over the next five years.

The Base Case sits within the uncertainty envelope provided by the FES 17 Future Energy Scenarios:

Figure 9: FES 2016 Transmission connected nameplate capacity to 2021/22

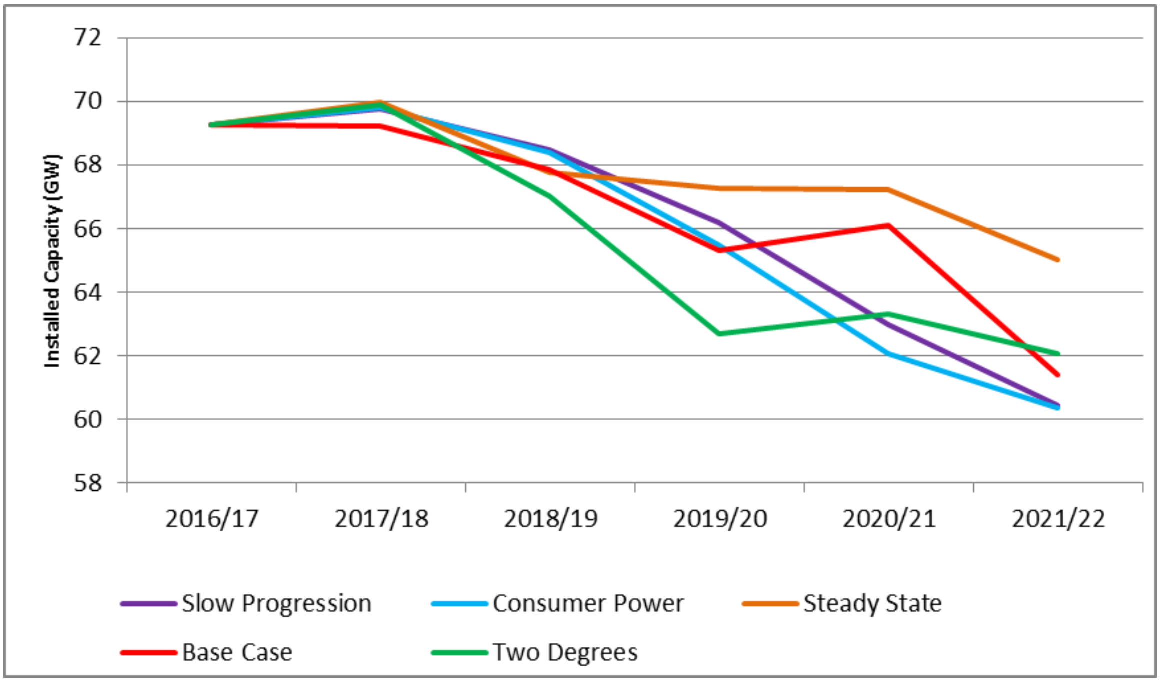


Table 6: Transmission connected nameplate capacity (GW) to 2021/22

Capacity GW	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Two Degrees	69.3	69.9	67.0	62.7	63.3	62.1
Slow Progression	69.3	69.8	68.5	66.2	63.0	60.4
No Progression	69.3	69.8	68.4	65.5	62.1	60.4
Consumer Power	69.3	70.0	67.8	67.3	67.2	65.0
Base Case	69.3	69.2	67.9	65.3	66.1	61.4

3.6 Generation Capacity 2022/23 onwards

Each of the FES scenarios has a generation background that is based on the underlying scenario assumptions. These generation backgrounds include varying amounts of renewable / low carbon capacity, and differing volumes of Capacity Market eligible plant.

Capacity Market eligibility

Any generation capacity which is currently receiving, or will receive, support under the following initiatives is not eligible for the Capacity Market:

- Contracts for Difference (CfD)
- Final Investment Decision Enabling Regime (FIDeR)
- Feed in Tariffs (FiT)
- Renewables Obligation (RO) now closed to new applications, but some capacity will continue to receive support.

However once a plant stops receiving support under these schemes, it will become eligible for the Capacity Market.

In addition, any generation capacity that is under a total capacity of 2 MW is assumed not to be eligible for the Capacity Market in this modelling – although any plant under 2 MW not receiving support from the above schemes can enter the auction if combined with other capacity by an aggregator. This latter group is estimated to range from 1.1 GW to 1.6 GW in the period to 2021/22 depending on the FES scenario and year and includes some onsite autogeneration above 2MW assumed to opt out of the Capacity Market. Note that small scale renewable technologies are assumed to receive FiT support and therefore are excluded from this range.

Lastly, any capacity that is receiving a Capacity Market Agreement for longer than one year will not be eligible for successive auctions until its existing CM Agreement(s) end.

Assumptions

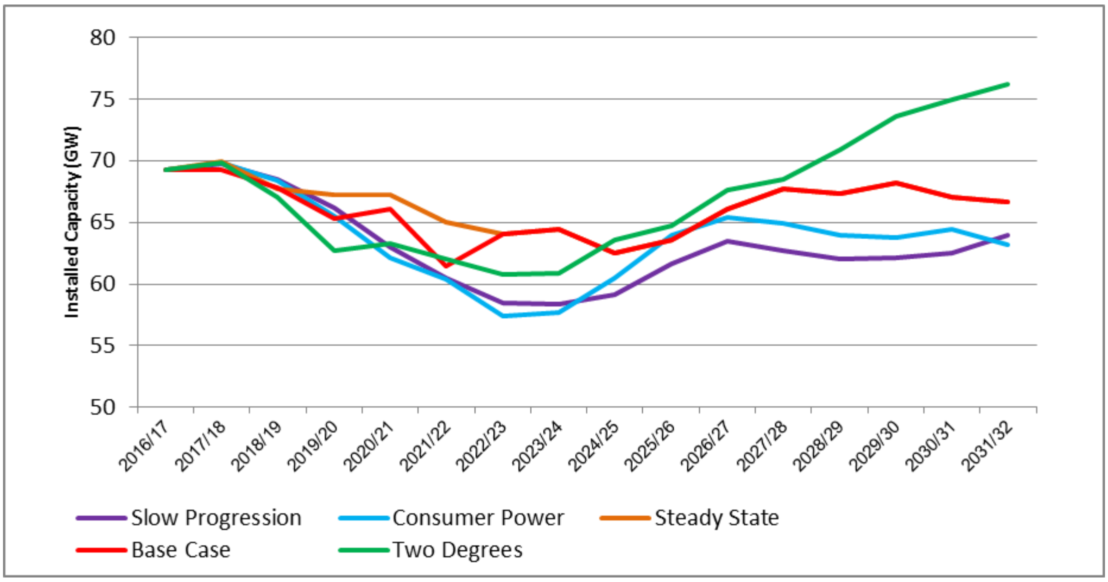
Barring these exceptions based on size and support mechanism, all other forms of generation capacity are eligible for the Capacity Market. For the purposes of our modelling, we assume that:

- All eligible capacity will enter the Capacity Market and
- No capacity will opt out and remain operational

However, the recommended capacity to secure will be adjusted for known opted out plant following the pre-qualification process.

The focus of the modelling is to estimate the total eligible de-rated capacity that needs to be secured in order to achieve a reliability standard of 3 hours LOLE or lower. The final mix of generation technologies that make up this total capacity will be decided by the capacity auction and is not predetermined as a result of the modelling. A breakdown of installed capacity for each FES scenario is shown below:

Figure 10 : FES 2016 transmission connected nameplate capacity to 2031/32



For detailed breakdown of generation between CM and non-CM see Annex.

3.7 Distributed Generation

The scenario projections for distributed generation (generation which is connected to the lower voltage distribution networks) considers what plant is currently operating, and what plant may close and open in the future

The scenarios consider 30 different existing technologies, as well as considering new types of generation that may connect in the future. The contribution of each of these technologies to peak demand is also taken into account – so for example, solar is excluded from these projections, due to the fact that it is unable to contribute to peak demand which currently takes place in the hours of darkness.

A variety of data sources are used to develop a list of projects for existing generation above 1MW in size. We are continually seeking to improve the data available, as well as our analysis, in order to have an improved picture of how distributed generation operates over the year. This will help us to improve our understanding of how small scale plant contributes to demand across the seasons.

The ECR uses overall underlying demand (See Section 3.4). For other purposes, demand on the transmission network can be calculated using the output from distributed generation netted off overall demand.

Figure 11: Distributed generation nameplate capacity (excluding Solar) to 2021/22 (GW)

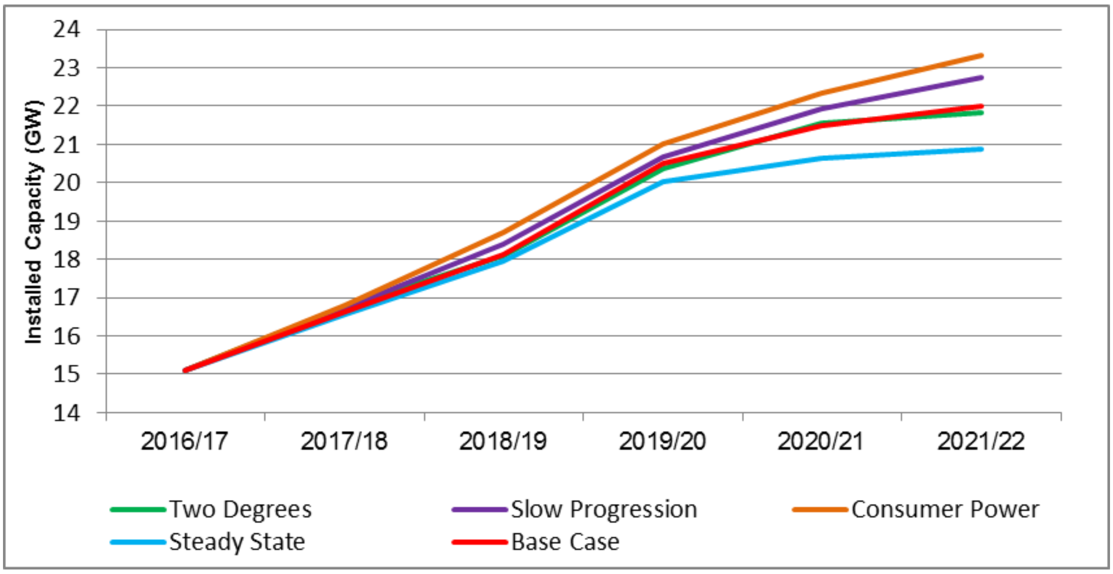
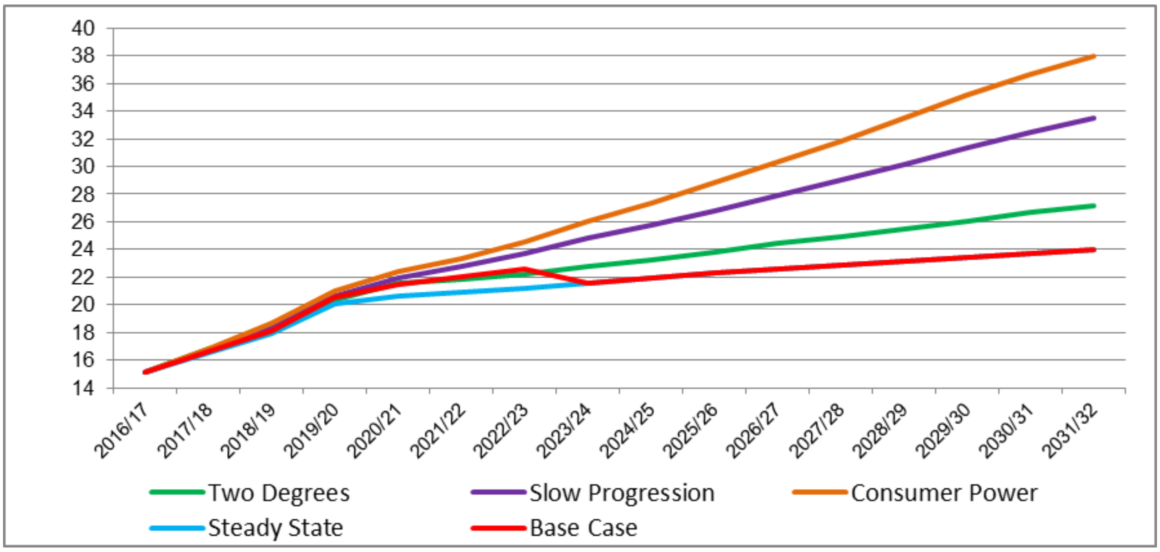


Table 7: Distributed generation nameplate capacity (GW)[23]

Capacity GW	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Two Degrees	15.1	16.8	18.1	20.4	21.5	21.8
Slow Progression	15.1	16.7	18.4	20.7	21.9	22.7
Steady State	15.1	16.8	18.7	21.0	22.4	23.3
Consumer Power	15.1	16.6	17.9	20.0	20.7	20.9
Base Case	15.1	16.6	18.1	20.5	21.5	22.0

Figure 12: Distributed Generation (excluding Solar) to 2031/32 (GW)



[23] Includes capacity <1 MW

3.8 Demand Side Response

In the FES, DSR has been defined as a deliberate change to an end user's natural pattern of metered electricity consumption brought about by a signal from another party. That is, demand shifting or demand reduction and not the use of generators to substitute the supply source. So, for instance, Triad avoidance is made up of both demand reduction (we estimate about 63%) and switching to an alternative supply source. Within our definition of DSR we consider only the demand reduction element.

Domestic Peak Response

We believe there are three other factors which must work in tandem to give the most flexibility at the lowest cost to consumers. These are:

- Smart Meters: These only have a short-lived behavioural impact by themselves. Their impact is enhanced where they are supported by appropriate marketing and education around energy use. We see this happening more in the greener scenarios. Only in Two Degrees do we see the government's roll-out plan being delivered on time.
- Smart Technology: These are appliances that have two-way communication capability and interact with the consumer and other parties; for instance Hive or Nest. As the technology improves service providers such as aggregators have a greater role to play.
- Smart Pricing: The appropriate use of time of use tariffs (TOUTs). TOUTs incentivise consumers to move those energy demanding activities, which can be moved, to off peak times. The more engaged consumers, energy suppliers and government are, then the greater the effects of TOUTs.

Industrial and Commercial DSR

In this year's FES we assume three interplaying parts which, if correctly combined, will produce the optimal outcome for businesses to make use of their flexible capability through DSR. These are:

- Income generation from supplying network services
- Information communication technology (ICT) allowing easy data access
- Savings from reduced charges.

Results of the Capacity Market auctions have been utilised in the modelling. The various criteria of proven, unproven, cleared and failed have been used, where appropriate, for the different scenarios.

Data from National Grid's balancing service have also been used, in particular the Short Term Operating Reserve. This is anticipated to reach its maximum transition from STOR to the Capacity Market by 2021.

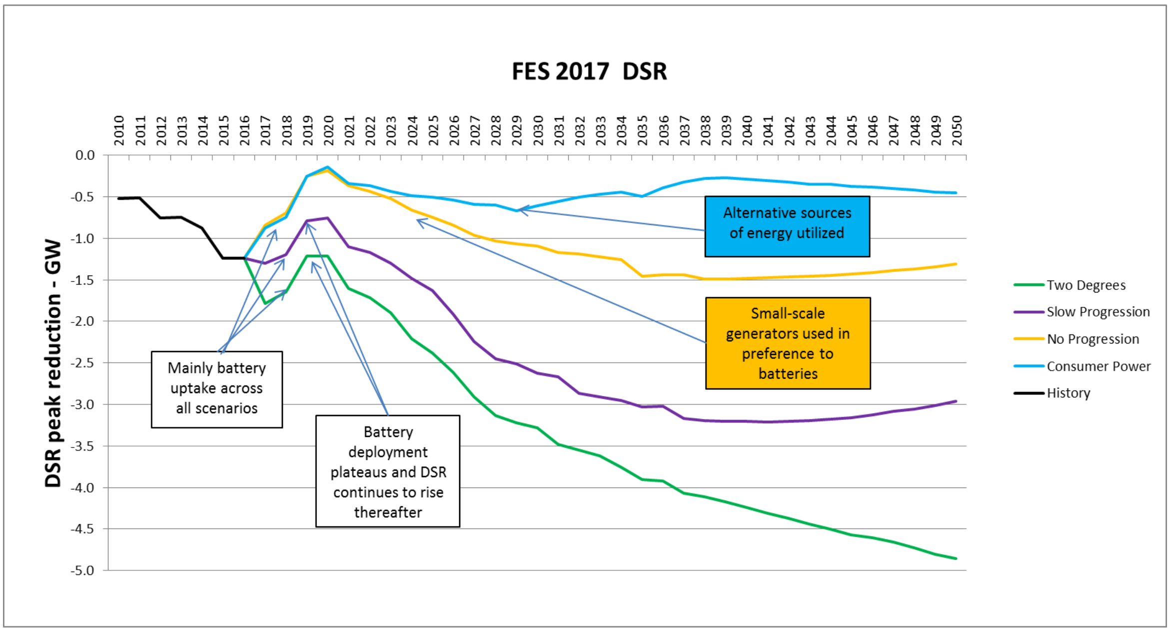
Batteries and onsite generation will increasingly come into play and offset the requirement for demand shifting and we see a noticeable effect from the growth in batteries up to 2020 when battery development plateaus. The demand will not shift however the power source will. In the less green scenarios we see small scale generation being used more and their use will drive down the GW savings on our definition of DSR.

ICT developments will be key. Businesses or aggregators with better data will be able to make more informed decisions to reduce their consumptions particularly at peak times.

Savings can be made by reducing exposure to network charges or avoiding peak time tariffs. In the future smaller business, with the aid of aggregators with suitable ICT could also take advantage of these schemes.

The projections of the industrial and commercial DSR profile reductions have changed since the last FES publication and the results can be seen in the graph below.

Figure 13: Industrial and Commercial DSR profile reduction[24] to 2050



2017 FES Outcomes

The range of DSR over the four FES scenarios in 2021/22 is from 1.7 GW to 3.1 GW.

For the purpose of this report (and the Future Energy Scenarios report) we consider DSR to be industrial and commercial (I&C) demand shifting only. I&C demand shifting reductions is provided in the table below for selected years:

Table 8: I&C demand shifting reductions (GW)

GW reductions (I&C)	2016/17	2021/22	2025/26	2031/32
Two Degrees	1.3	3.1	3.9	5.3
Slow Progression	1.3	2.3	2.9	3.8
Steady State	1.3	1.7	2.0	2.5
Consumer Power	1.3	1.9	2.4	3.2

[24] Figure 13 includes batteries/behind the meter generation hence it is lower to demand shifting DSR in Table 8

Power Responsive

Power Responsive is a stakeholder-led programme, which National Grid is facilitating. The purpose is to facilitate growth of participation of flexible technologies, including demand side response and storage, in GB energy markets. It involves all stakeholders in the value chain, including the customers from the flexible technologies.

Since the programme launched in summer 2015, there has been a substantial momentum growth across the industry in the desire to facilitate flexible technologies in to energy markets. Around 1500 individuals have signed up to be informed on the programme so far and informative materials on opportunities to participate have been published, including a “comprehensive guide to DSR” for energy managers in collaboration with the Major Energy Users Council. There are also regular open forum working groups which are run quarterly for both DSR and Storage sectors.

3.9 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects. We have anonymised the data by showing only the total capacity per year, due to commercial sensitivities.

We identified potential projects and their expected commissioning dates to connect to GB. This information was from a range of sources including the electricity European Network of Transmission System Operators (ENTSO-e) ten-year network development plan, 4C Offshore and the European Commission. Where only a commissioning year was given we assumed the date to be 1 October of that year. We assessed each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it did not meet the minimum criteria we assumed it will not be delivered in the given scenario, or that it will be subject to a commissioning delay. We calculated this delay using a generic accelerated high-voltage direct current (HVDC) project timeline. All projects which have reached final sanction are delivered, though they may be subject to delays in some scenarios.

In all scenarios we assumed that the supply chain has enough capacity to deliver all interconnector projects. For the Base Case we have selected the Consumer Power scenario.

Table 9: Export Capacity Levels for Interconnection (in GW)

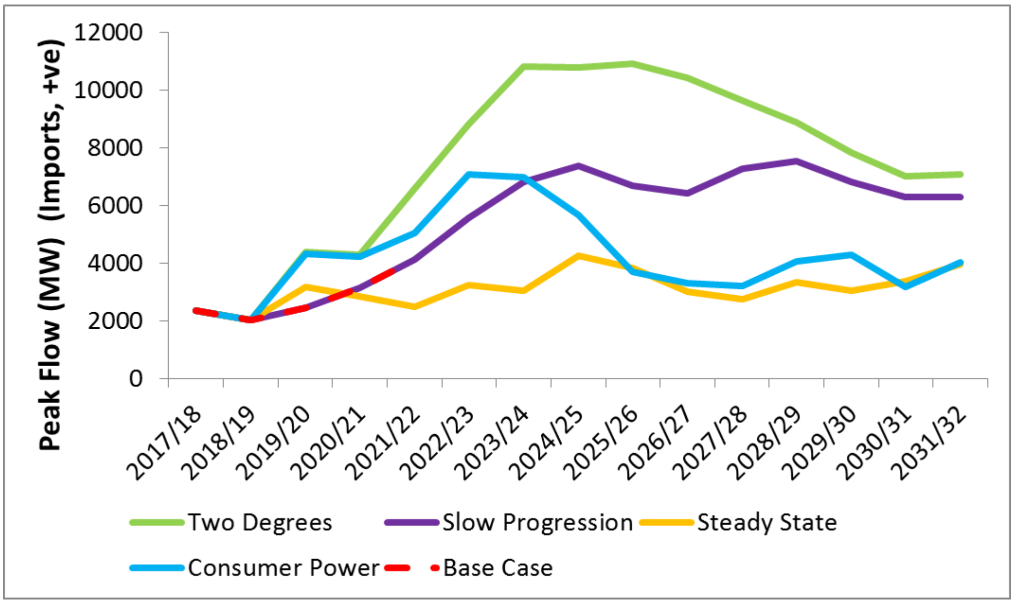
Capacity GW	2018/19	2019/20	2020/21	2021/22	2025/26	2030/31
Base Case	4.0	5.0	5.0	6.0	13.2	16.5
Two Degrees	4.0	5.0	5.0	7.4	15.6	18.5
Slow Progression	4.0	4.0	5.0	6.0	11.2	15.0
Steady State	4.0	4.0	4.0	4.0	8.4	9.8
Consumer Power	4.0	5.0	5.0	6.0	13.2	16.5

The highest electricity interconnector capacity is in Two Degrees. This scenario assumes available investment to deliver new projects, supported by an enabling regulatory / political environment. Interconnector capacity is lowest in Steady State. This scenario assumes lower available investment and a less supportive regulatory / political environment to deliver new projects.

Interconnector capacities in both Consumer Power and Slow Progression fall in between these limits. Consumer Power is a market-driven scenario. So while there is available investment for new projects, there may be fewer opportunities to deliver new projects that depend on regulatory initiatives such as Ofgem's Cap and Floor. This results in lower interconnector capacity than Two Degrees. In Slow Progression, we assume that there is lower available investment for new projects. Despite there being a more supportive regulatory / political environment for new projects, the lower investment means interconnector capacity is also lower.

Last year, we commissioned external consultants (Baringa) to assess the flows between GB and connected countries for each scenario using a pan-European market model. This year we have carried out this analysis in-house using a pan-European market model that we have procured from Pöyry (Bid3)[25]. Flows were modelled for each scenario based on the latest FES 2017 data for GB. Data for non-GB countries was informed by a number of sources including data available from European Transmission System Operators and ENTSO-E.

Figure 14: Peak interconnector net flows



In FES 2017 we define peak flows, shown in Figure 14, as the flows which we expect to flow when Great Britain needs imports during winter peak periods. Winter peak periods have been defined as 17:00 – 20:00 GMT, Mon – Fri, Nov – Feb. All scenarios show net imports at times of peak GB demand over the whole time period. Actual flows during these times could vary significantly from these values due to the impact of other factors such as wind generation and the system tightness of connected markets.

It should be noted however, that these flows at peak are not used in the CM modelling. For 2021/22, the CM modelling uses the probabilistic distributions from the Bid3 simulations rather than the single snapshot shown above. For 2018/19, a base assumption has been used for the contribution from interconnectors based on de-rating factors previously used in the CM Auctions.

[25] http://www.poyry.com/BID3

3.10 Sensitivity Descriptions and Justifications

The analysis assumes that the Future Energy Scenarios (FES) will cover uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), interconnection and generation.

While the FES scenarios vary many variables (see list of Scenario Framework in Annex) the sensitivities vary only one variable at a time. Each of the sensitivities is considered credible as it is evidence based i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. The sensitivities cover uncertainty in weather, wind, peak demand, over-delivery and non-delivery of contracted capacity. In addition, for 2018/19 only, there are sensitivities covering station peak availabilities and a range of interconnector peak flows.

To provide the reference case to which the sensitivities have been applied, a Base Case has been utilised. Up to 2021/22, the Base Case consists of our “central view” of the demand and generation backgrounds which aligns with the DFA Incentive and aims to reduce the likelihood of over or under securing capacity thereby minimising the associated costs to consumer. From 2022/23 the Base Case takes the demand and generation mix from the Steady State scenario.

The sensitivities are described below. However, there are small differences in the way that these sensitivities were applied to each of the individual year runs: the elements that are different in each year are described in the chapters relating to those years.

3.10.1 Low Wind (at times of cold weather)

As detailed in Section 2.5 of the 2016 ECR, statistical analysis undertaken by Edinburgh University and Heriot Watt University recommended the inclusion of a low wind sensitivity. In line with the recommendation, this sensitivity models the impact of lower wind generation than the base assumption at times of cold weather (i.e. at times of high demand). To model this sensitivity a scaling of 0.8 (0.9 is base assumption) is used (i.e. wind output is reduced linearly from 100% of its unscaled value to 80% for daily peak demands between the thresholds of 92% and 102% of peak demand).

3.10.2 High Wind (at times of cold weather)

As detailed in Section 2.5 of the 2016 ECR, statistical analysis undertaken by Edinburgh University and Heriot Watt University recommended the inclusion of a high wind sensitivity. In line with the recommendation, this sensitivity models the impact of higher wind generation than the base assumption at times of cold weather (i.e. at times of high demand). To model this sensitivity a scaling of 1.0 is used i.e. this sensitivity assumes that wind output is independent of daily peak demand).

3.10.3 High Plant Availabilities

Availability sensitivities have been included for 2018/19 only as they have no material impact on 2021/22 analysis. The high and low plant availability sensitivities address the statistical uncertainty associated with determining the mean availabilities of each fuel type. The mean availabilities are determined based on the last 7 years, which is too small a sample size (i.e. just 7 data points) to be confident that the means of these distributions will be statistically representative of what could happen in the future. The plant availability sensitivities are not intended to address concerns of whether the base availability assumptions are too high or too low, and nor are they intended to make predictions as to what levels of plant availability we believe will occur. These are purely statistical sensitivities to address the uncertainty in calculating mean values from a small number of points. To allow for this in the modelling it assumes for two of the largest contributing generation technologies (nuclear and CCGT) a higher mean availability than the base assumption (see 2.4.3). This higher availability is also applied to any capacity for these technologies contracted in previous auctions.

For existing nuclear the availability increases by over 4% from just 85% to 89% and for CCGTs by 3% from 89% to 92% in 2018/19. These higher availabilities are based on one standard deviation above the mean of observed figures from the last seven years. Coal availabilities have not been flexed as coal availabilities show very little variance over the last seven years. In addition, other technologies have not been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their high availability levels.

In 2018/19 for example, adjusting availabilities has an impact on the de-rated capacity of previously contracted plant and therefore a small impact on the de-rated total required. However, it clearly has a large impact on the name plate capacity total. These adjustments have been applied to the technologies that are both large in aggregate GWs and have shown variance across the sample.

3.10.4 Low Plant Availabilities

Availability sensitivities have been included for 2018/19 only as they have no material impact on 2021/22 analysis. The low plant availability sensitivity assumes for two of the largest contributing generation technologies (nuclear and CCGT) a lower mean availability than the base assumption (see 2.4.3). For nuclear the availability reduces from 84% to 82% and for CCGTs from 89% to 85% in 2018/19. These lower availabilities are based on one standard deviation below the mean of observed figures from the last seven years.

3.10.5 Interconnector Assumptions & Sensitivities (2018/19 only)

In the 2017 ECR, interconnector capacities are based on the FES scenarios (see section 3.9). For the 2021/22 model runs the flows are calculated as part of the probabilistic modelling hence there is no requirement for interconnector sensitivities. However for the 2018/19 analysis interconnectors are modelled using static peak flow level assumptions. A Base Case flow assumption and a range of flow sensitivities around this assumption was therefore used in the 2018/19 analysis. A similar approach was used in the 2014 ECR when modelling the capacity to secure in the 2018/19 T-4 auction albeit with a different range and base assumption.

To be consistent with the treatment of interconnectors in the various auctions to date we have assigned de-rating factors (France 59%, Netherlands 74% & Ireland 20%) that result in a base flow of 2100 MW with range of sensitivities for net imports ranging from 3500 MW to 700 MW i.e. ±1400 MW around the base flow.

Within the net import sensitivities; flows to Ireland were varied from an export of 500 MW to an import of 500 MW. The following table summarises the four interconnector sensitivities together with the base assumption where a positive number indicates imports and a negative number exports and the net flow shows the combined value for the Continent and Ireland.

Table 10: Peak interconnector flow level assumptions (2018/19 only)

Assumed Flow (MW)	Continent	Ireland	Net Flow
Base	1900	200	2100
700 Imports	1200	-500	700
1400 Imports	1500	-100	1400
2800 Imports	2500	300	2800
3500 Imports	3000	500	3500

3.10.6 Weather – Cold Winter

The cold weather sensitivity addresses the uncertainty in demand due to cold winter weather conditions. Demand is highly sensitive to weather and a cold winter will lead to higher demand which increases the risk of loss of load. This sensitivity is included because the modelling uses a relatively short history of demand in the LOLE calculation, which is based on 11 years. This is too small a sample to be confident that the demand distributions will be statistically representative of future weather conditions. For example, the Met Office uses a much longer period of 30 years when calculating average temperatures.

The cold weather sensitivity is based on a recent cold winter and calculates LOLE assuming that the weather that occurred in 2010/11 is repeated. This winter was not extreme compared to the last 30 years; we would expect similar weather every 1 in 9 years. In addition the weather data is "pooled" rather than being conditional on each winter, which is standard practice in many countries, hence it is statistically sound to run this sensitivity as well as the warm winter sensitivity.

The final reason for including this sensitivity is reputational as this sensitivity is clearly credible given that the winter was less than 7 years ago, was not extreme and from a practical communications point it would be extremely difficult to defend a position that did not consider it in the calculation.

3.10.7 Weather – Warm Winter

This warm weather sensitivity is included on the same statistical basis as cold weather, and ensures that the treatment of the uncertainty of demand due to weather is unbiased. The warm weather sensitivity is based on a warm winter from within the last 11 years and calculates LOLE assuming that the weather that occurred in 2006/07 is repeated. This winter was not extreme and when compared to the last 30 years, we would expect similar weather every 1 in 14 years.

3.10.8 High Demand

In the 2015 ECR, the high and low demand sensitivities were based around the range of historical forecasting performance for Transmission level demand for the winter ahead (see 2015 ECR for the rationale behind this). This produced an asymmetric range of demand sensitivities reflecting the tendency to over forecast demand mainly due to the rapid growth in distributed generation and the lack of visibility of both capacity and generation data and secondly, the prolonged economic recession which suppressed demand longer than expected. These two factors may be less relevant in the future due to improved access to data on distributed generation and the view by economists that a recession in GB of the magnitude seen around 8 years ago is unlikely.

National Grid now has the DFA Incentive and an obligation to publish how it plans to improve the demand forecasting process every year. Consequently, the demand sensitivities have been aligned with the ranges used within the incentives rather than historical performance. The DFA Incentive for the T-1 auction has a symmetric range of +/- 2% which forms the basis of the sensitivities in the 2016 and 2017 ECR. We have not used the T-4 incentive range of +/- 4% as the incentive is weighted towards the T-1 demand given that there is an opportunity (in the T-1 recommendation) to correct any forecast errors in the T-4 demand.

The high demand sensitivity covers the upper end of the range of uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This assumes peak demand values that are 2% above the FES ACS peak demands.

3.10.9 Low Demand

The low demand sensitivity covers the lower end of the range of uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This assumes peak demand values that are 2% below the Base Case ACS peak demands.

3.10.10 Non-delivery

Previously non-delivery sensitivities were dominated by the risk around coal closures given their challenging economic situation and environment legislation. However, new risks have materialised that could add to the non-delivery e.g. policy around Ofgem’s embedded benefits consultation, non-delivery risk from unproven DSR failing to materialise (as seen in the 2016/17 TA) and energy limited technologies like battery storage being unable to deliver for the duration of a loss of load event.

We considered creating separate sensitivities for each element of the non-delivery risk but decided against this as they all interact resulting in non-delivery which can then lead to a market response to countervail the non-delivery i.e. wholesale prices rise as more stations close thus limiting the level of closures. In addition if the elements were separated out how far do we go e.g. down to individual stations? If so this would result in non-delivery sensitivities having virtually no impact on the LWR calculation and therefore CM auction recommendation as the sensitivities would only have small adjustments away from the Base Case and thus the risk of non-delivery has not been incorporated in the modelling.

Consequently, we developed non-delivery risks associated with coal plant, small scale embedded plant (from the 2014 and 2015 auctions), unproven DSR and battery storage with a market response that limited the range to 4.0GW. During this process we discussed the various options with BEIS and the PTE to determine the final range and we are keen to continue to work with the PTE in developing this analysis further in preparation for next year’s report.

The non-delivery sensitivities deal with uncertainty risks and also assist with the granularity in the LWR calculation. A range of non-delivery sensitivities with incremental steps of 0.4GW (around the de-rated capacity of a typical coal power station unit) have been modelled up to a maximum of 2.8GW in 2018/19 and 4.0GW in 2021/22.

3.10.11 Over-delivery

This sensitivity considers the possibility of over delivery i.e. stations staying open that do not have CM contracts and interconnectors importing more than their CM contracted de-rated capacities. The former is more likely to apply to the shorter time period associated with the T-1 auction as stations are less likely to stay open in the market for the longer T-4 period without a CM contract in any of the intervening years. However for the latter interconnectors, assuming capacity is available in the connected markets, can deliver higher imports supported by market coupling across physical boundaries within the internal energy market. Consequently, we have agreed with BEIS and the PTE to include up to 1.2GW over delivery out to 2021/22.

3.10.12 Sensitivities Considered but Rejected

A number of alternative sensitivities were considered for inclusion but following discussions with BEIS and the PTE were rejected. These are listed below.

Dependence of Generating Units - The DDM implicitly assumes independence in availability of generating units. A number of commentators/consultancies have suggested that this assumption is optimistic. For example, a fault in one unit can affect the other units on site or a station transformer fault could affect more than one unit or the operation of a station within a portfolio could be affected by the other stations in that portfolio. However, the data available associated with these issues is either very limited or difficult to interpret and translate for use into the future, making it very difficult to quantify for modelling purposes. Hence this sensitivity was not included.

Renewable Plant Non-Delivery - This sensitivity was to reflect slippage in non-CM plants away from their connection and contract dates similar to the CM non-delivery sensitivities. However, following discussions with BEIS and the PTE it was agreed not to include this sensitivity since there is a credible range in the level of renewable generation connecting across the four FES scenarios and Base Case.

Black Swan Events – These are defined as events that have low probability but high impact. Examples for GB would include large nuclear type faults, extreme weather e.g. Jan. 1986/7, significant technology closures due to economics or policy plus issues not yet identified. We have investigated nuclear type faults before and concluded that they were low probability and historically had been rectified ahead of the following winter (albeit with stations operating at a reduced capacity but this would be covered in the scenarios). We have also considered extreme cold weather (e.g. Jan.1986/87) combined with low wind, but this would involve changing more than one element which violates the principles behind the sensitivities of only including credible outcome by changing one variable. Given this and the economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with BEIS and the PTE not to include any “black swan” event sensitivities.

CMU misalignment to TEC – This sensitivity relates to the CMUs (Capacity Market Units) connection capacity being greater than TEC (Transmission Entry Capacity) values for some transmission connected stations so that when the de-rating factors are applied they result in nearly 100% availabilities for many stations.

This clearly puts security of supply at risk, as no plant is 100% available in reality, thus the auction has under secured capacity. However, our modelling mitigates this risk by only using capacities based on TECs, so all our recommendations take account of this anomaly as best it can, with only the T-1 auction potentially under procuring if the stations successful in that auction have CMUs greater than TECs. Hence we have agreed not to include this sensitivity.

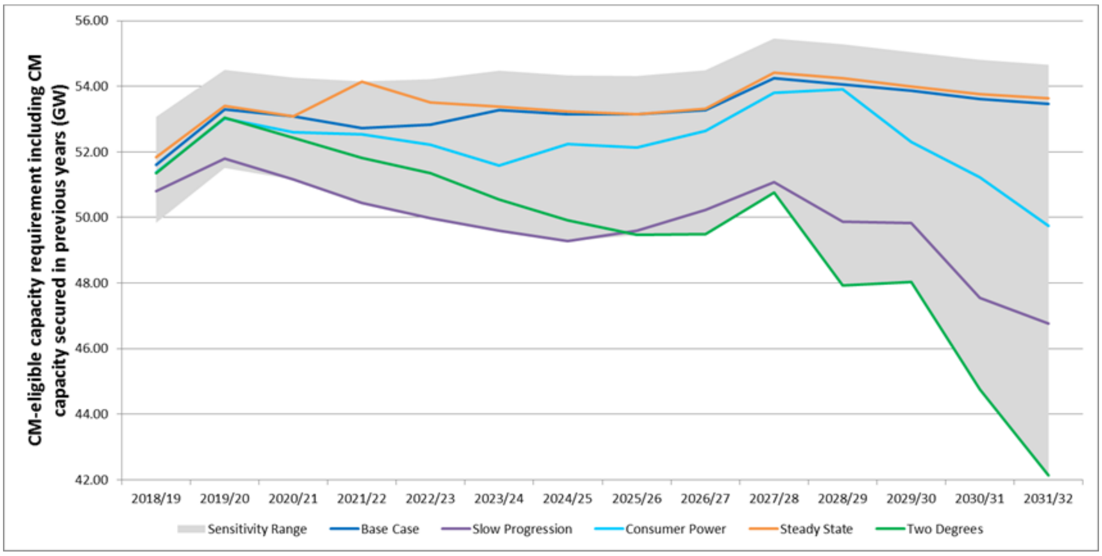
Combined Sensitivities – A number of system operators around the world consider combined sensitivities within their process for calculating the required capacity to meet their respective reliability standards. Consequently we investigated whether this was appropriate for the GB process particularly in relation to the use of a potential hybrid approach (see Annex). First of all we considered the potential use of combined sensitivities within the LWR decision tool. We concluded that this would, if included, result in lower probability sensitivities such as combined sensitivities being given equal weightings as sensitivities with only one variable changed which would be inappropriate. Secondly we considered it as part of the hybrid approach but to change the answer materially required such a low probability sensitivity that it may be considered more like a “black swan” event and was thus decided not to include.

3.11 15 years horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2018/19 and 2021/22). It focuses on the total requirement for CM-eligible capacity and does not split each year’s requirement into capacity secured in earlier years, T-1 and T-4 auctions. The requirement in 2018/19, 2019/20 and 2020/21 was derived from the 2018/19 model runs (see Chapter 6) and the capacity requirement from 2021/22 to 2031/32 from the model runs for 2021/22 (See Chapter 5). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

The following chart (Figure 15) shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years.

Figure 15: Total CM-eligible Capacity required in Future Years



The requirement in 2018/19 is lower than the surrounding years mainly due the fact that interconnectors are not allowed to participate in the Capacity Market, reducing the CM-eligible requirement in that year by the level of the assumed peak interconnector flow. Note that the total requirement for the non-delivery and over-delivery sensitivities is the same as the Base Case. For non-delivery cases, the increase in capacity required is offset by the reduction in contracted capacity closing before the target year. Similarly for over-delivery cases, the decrease in capacity required is compensated for by CM-eligible plants providing additional capacity without a contract.

As can be seen in the chart, the Steady State scenario has a relatively stable capacity requirement over the period whilst the remaining three Future Energy Scenarios show a gradual decline over most of the period as the level of de-rated RO/CfD supported capacity increases by more than any growth in peak demand (plus reserve for largest infeed loss). However, in all scenarios there is a small increase in 2027/28 when RO support for biomass conversion ends.

There could be a risk of stranded assets receiving support if new capacity is built for one year and then not required in the future. However, given the current emissions regulations, in particular the Industrial Emissions Directive (IED), a number of power stations will have to close by 2023 or when they have exhausted their allocated 17,500 running hours. Furthermore in the case of coal power stations, the Government's policy is to close all unabated units by 2025. The current nuclear fleet will also see a number of closures over this period, due to units reaching the end of their safe operational life. These closures of existing capacity will ensure that any new capacity built in the first few years of the capacity market will still be required in later years.

The chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2018/19. For 2017/18, we did not model the capacity requirement in each scenario / sensitivity as the capacity auction for that year has already happened, securing around 54.4 GW of de-rated capacity[26]. The forthcoming 2017/18 Winter Outlook Report[27] will include a view of electricity security of supply for the coming winter.

[26] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/EA%2017-18%20Final%20Results.pdf
[27] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

4. De-rating Factors for CM Auctions

4.1 Conventional Plants

Conventional plant de-rating factors are based on the station availabilities as shown in Chapter 2 and the Annex and are updated annually as part of this process. The table below shows the proposed de-ratings factors for 2021/22 by the conventional generation technologies and includes a comparison with those used last year for the 2016 T-4 Capacity Market Auction[28].

Table 11: Conventional Plant De-rating Factors

Name for technology class	Plant Types Included	De-rating factor (ECR 2016)	De-rating factor (ECR 2017)
Oil-fired steam generators	Conventional steam generators using fuel oil	85.44%	88.04%
OCGT and reciprocating engines (non-autogeneration)	Gas turbines running in open cycle fired mode Reciprocating engines not used for autogeneration	94.17%	94.81%
Nuclear	Nuclear plants generating electricity	84.36%	85.24%
Hydro	Generating Units driven by water, other than such units: driven by tidal flows, waves, ocean currents or geothermal sources; or which form part of a Storage Facility	86.16%	87.92%
Storage	Conversion of imported electricity into a form of energy which can be stored, the storing of energy which has been converted and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage hydro stations) and battery storage technologies.	96.29%	96.11%
CCGT	Combined Cycle Gas Turbine plants	2017/18 87.60% 2018/19 88.00% 2020/21 90.00%	2018/19 88.54% 2019/20 89.00% 2021/22 90.00%
CHP and autogeneration *	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%	90.00%
Coal/biomass/energy from waste	Conventional steam generators using coal or biomass or waste	86.92%	87.58%
DSR		86.88%	86.34%

*De-rating factors of these technologies were provided by BEIS

[28] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/71/Capacity%20Market%20Auction%20Guidelines%2015th%20November%202016.pdf

The de-rating factor in table above for battery storage presently relates to the same underlying number as historical GB pumped hydro performance over the last 7 years. This mapping of battery storage to pumped hydro was necessary in the past as there had been little or no battery storage on the GB system to date and thus an approximation was allowable, and further no system performance data with which we could develop a performance based de-rating factor existed. However, anecdotal market intelligence would suggest that some of the batteries that were successful in the recent T-4 2020/21 auction may have significant energy duration limits of as short as 30 minutes. A system capacity adequacy event on the GB system could endure for a number of hours longer than this, and thus a pumped hydro equivalent de-rating factor may no longer be appropriate for some batteries.

Cognisant of the growing importance of battery storage to the GB capacity market, and to reflect significant industry commentary on the matter in recent times, National Grid will be running a development project (using the DDM and Unserved Energy Model (UEM) reliability assessment tools from LCP[29]) in Summer/Autumn 2017 to update the de-rating factor allocated to battery storage to one which is more indicative of it’s true capability. We expect that a range of de-rating factors may thus be produced which could potentially be used in future, based on the range of duration limits that some future GB market batteries may have, as well as the overall penetration of energy limited resources on the system, and these will be published prior to prequalification for the upcoming T-1 and T-4 auctions later this year.

4.2 DSR De-rating Factor

The De-rating factor for DSR CMUs is the Average Availability of Non-BSC Balancing Services (“AABS”)

- It is calculated by determining the mean average of the declared availabilities of all Non-BSC Balancing Services providers at real time in High Demand Settlement Periods over the three immediately preceding Core Winter Periods, divided by their contracted volumes.

- Short Term Operating Reserve (STOR) availability was chosen as a basis for these calculations as this is the largest, most accurate and relevant data set available to National Grid. Availability information following settlement also includes the effect of any utilisation failure, so this provides a more accurate view than declared availability. Note there is a low volume of other applicable Balancing Services data available such as FCDM (Frequency Control Demand Management) and FFR services (Firm Frequency Response) but these services are either not comparable to Capacity Market data, or the data is not sufficient to add value to the process.

- Only Committed STOR units, where a service provider must make the service available for all availability windows within the contracted season, were considered and used in the calculation. The availability of Flexible units is found to be low due to the nature of the load and hence the reason for the flexible service. When including Flexible STOR the de-rating factor was shown to decrease so was not used. The committed service also more closely reflects the capacity product than the other services. Currently

[29] Lane, Clark and Peacock LLP http://www.lcp.uk.com/

contracted unit data was used as this reflects the current market rather than units that may have left the market due to low performance.

Details of the DSR De-rating Methodology can be found on the EMR delivery body website[30].

4.3 Interconnectors

Interconnectors are not eligible to participate in the 2018/19 T-1 auction but will be eligible to participate in the 2021/22 T-4 auction. The future of potential flows through interconnectors is very uncertain and as a consequence there is no single answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid, in agreement with BEIS and the PTE, has considered in determining an appropriate country's de-rating factor range for the Secretary of State to then decide the factors to apply to interconnectors in the 2021/22 T-4 auction.

4.3.1 Methodology

As with previous years there are two elements to the methodology for calculating interconnector de-rating factors: an analysis of historical flows and price differentials between the two markets and stochastic modelling of the future European electricity market. BEIS commissioned Pöyry to update their analysis of historical de-rating factors used to inform last year's ranges. These historical de-rating factors set the floor of the range for all countries except for Ireland and Norway. It only sets the lower bound of the recommended range when stress test runs are at or below the historical values.

National Grid has a new pan-European market modelling team which uses the Bid3[31] program to model flows between GB and connected countries for each scenario. Bid3 is a dispatch model based on short-run marginal costs. It simulates hourly demand and renewable generation based on historical weather patterns and then allocates flows between countries using linear programming to optimise the cost of generation to meet demand across all modelled countries. The new team and model has enabled the pan-European modelling to be run later than previous years so that the latest forecasts can be used. Flows were modelled for each scenario based on FES 2017 demand and generation data and FES 2017 electricity interconnector capacities for GB combined with a single scenario for non-GB countries. The demand history was increased to 29 years (1985 to 2013). It is correlated across Europe and with wind generation. This increases the number of periods with extreme weather across Europe, giving greater confidence in the ability of interconnectors to import when required.

The model assumptions were stress tested by running additional simulations with demand increased by 5% to check the impact of tighter margins on flows.

All hours with a GB capacity margin, excluding interconnector flows, less than or equal to 500 MW were selected to represent times when imports were required. The average flow as a percentage of capacity was 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.

[30] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf
[31] http://www.poyry.com/BID3

An additional set of de-rating factors was calculated from flows on winter weekday evenings. This selected the four hour period between 16:00 and 20:00 GMT from November to February, excluding weekends.

Table 12 lists the simulations.

Table 12: Pan-European modelling runs

Simulation	Graph name	Description
Pöyry historical analysis	Historical	Highest 50% of peak demand periods during winter quarter (7am-7pm business days, Dec-Feb, 2010-2016)
Average of FES scenarios	Average	Average of de-rating factors for BC, CP, SP, SS & TD
Base Case	BC	5 year forecast to 2021/22
Consumer Power	CP	2017 Future Energy Scenarios - Consumer Power
Slow Progression	SP	2017 Future Energy Scenarios - Slow Progression
Steady State	SS	2017 Future Energy Scenarios - Steady State
Two Degrees	TD	2017 Future Energy Scenarios - Two Degrees
Base Case + 5% demand	BC+5%	2017 Future Energy Scenarios - Base Case - All demand increased by 5%
Two Degrees + 5% demand	TD+5%	2017 Future Energy Scenarios - Two Degrees - All demand increased by 5%
Base Case with low Irish capacity margin	BC-LI	2017 Future Energy Scenarios - Base Case - Irish demand & generation adjusted to bring margins closer to 8 hour LOLE requirement
Two Degrees with low Irish capacity margin	TD-LI	2017 Future Energy Scenarios - Two Degrees - Irish demand & generation adjusted to bring margins closer to 8 hour LOLE requirement

As this is a new team working with a new model the potential of Bid3 has not been fully exploited this year. Over the summer development work will continue, to gain a greater understanding of the options available. We will also be improving our knowledge of connected markets with a view to developing a range of generation and demand assumptions to complement the GB scenarios.

4.3.2 Bid3 Pan-European Model Results

Table 13 shows the imports as a percentage of interconnector capacity from all the pan-European simulations. There are similar import percentages for Belgium, Netherlands and France but they all have different levels of demand and generation. This indicates that the flows are driven by the generation surplus over a wider area than just one country.

Where there are blanks in Table 13 that country is not connected to GB in that scenario for 2021/22. Norway only appears in Two Degrees and Belgium is not in Steady State.

The 5% increase in demand does not always reduce the de-rating factor for two reasons. Firstly there are many more hours that are brought into the calculation, so whilst the original selection of hours may have lower imports the additional hours may be less stressed over the whole of Europe enabling higher imports. Secondly, where the evening peak figures were originally low this could be due to price competition between countries. As margins tighten there will be more hours with prices high enough to increase flows.

Table 13: Simulation results: 2021/22 imports as % of interconnector capacity

	Historical Analysis	Average Low GB Margin	Low GB Margin (excluding interconnector flows)					Demand + 5%		Low Irish Margin	
			BC	CP	SP	SS	TD	BC	TD	BC	TD
France	48	80	76	90	85	63	88	72	78	81	90
Ireland	4	98	98	99	96	100	98	99	99	29	28
Netherlands	75	81	73	85	80	81	84	60	65	75	85
Belgium	65	85	78	90	87		89	71	76	79	90
Norway	85	99					99		95		99
	Historical Analysis	**Average evening peak**	**Evening Peak Hours 16:00, 17:00, 18:00, 19:00**					**Demand + 5%**		**Low Irish Margin**	
			BC	**CP**	**SP**	**SS**	**TD**	**BC**	**TD**	**BC**	**TD**
France	48	75	67	84	72	65	89	52	74	68	90
Ireland	4	42	32	57	32	30	61	42	67	13	28
Netherlands	75	72	64	80	67	66	85	55	71	65	85
Belgium	65	84	78	91	82		93	66	79	79	94
Norway	85	99					99		92		99

4.3.3 Pöyry historical analysis

BEIS commissioned Pöyry to update their analysis of historical flows. The methodology is specified in schedule 3A of the capacity market rules[32]. Table 14 shows this year's 7 year average historical de-rating factors compared to last year's figures. The historical data used was the top 50% of peak demand periods during the winter quarter, 7am to 7pm business days from 2010 to 2016. For the existing interconnectors the average de-rating factors are calculated for those periods where the price differential was positive and the interconnector was importing to GB. For new interconnectors the factors are calculated from the percentage of periods with a positive price differential. Interconnectors that have operated for less than 7 years are treated as new interconnectors and so their historical de-rating factors are based on price differentials only. Although the average historical de-rating factors have increased from last year, this is due to replacing very low 2009 values. Table 15 shows the annual historical de-rating factors. France, Belgium and Netherlands all show large falls in 2016 compared to 2015. This was due to lower availability of French nuclear generation because of outages for additional safety checks.

[32] https://www.gov.uk/government/publications/capacity-market-rules

Table 14: 7-year average historical de-rating factors

%	France	Netherlands	Ireland	Belgium	Norway
2009-2015	45	70	2	65	76
2010-2016	48	75	4	65	85

Table 15: Annual historical de-rating factors

%	2009	2010	2011	2012	2013	2014	2015	2016
France	1	20	26	50	68	69	79	25
Netherlands	31	58	68	78	84	83	89	64
Ireland	0	0	2	0	3	0	12	13
Belgium	27	59	63	64	75	79	87	31
Norway	35	39	86	88	97	99	85	98

4.3.4 Country de-ratings

The results for each scenario compared with the Pöyry historical averages are shown in Figures 16 to 20. The de-rating factors are calculated using the capacities in the model which represent assumed firm capacity adjusted for technical de-rating. This ensures that when BEIS applies adjustments to allow for technical de-rating and constraints there is not any double counting.

As this methodology is based around the modelling of European markets step changes in results could potentially occur between years due to changes in demand, generation mix and the resulting capacity margin. A problem in one country can impact flows from surrounding countries. Modelling flows across Europe for the auction year gives confidence that these interactions have been reflected in the recommended range of de-rating factors. However there is still uncertainty in the demand and generation numbers which we have addressed through stress tests. For example some countries have higher capacity margins than required to meet their stated security of supply. An example is Ireland where the standard run models the high capacity margin and a stress test run models a tighter market. As older thermal generation closes and capacity markets are used to support generation at the target LOLE level then de-rating factors are likely to fall. The 5% increase in demand gives an indication as to the impact of tighter margins.

The recommended ranges are produced by selecting the average of the four FES scenarios and base case without demand adjustments for the top of the range. The lower bound is selected from the Pöyry history for the last seven years only if one or more of the stress test runs are similar or lower. This is the case for all countries with the exception of Ireland and Norway which are based on the low Irish capacity margin sensitivity and Norwegian evening peak demand plus 5% sensitivity.

France:

The proposed range for France is 48% to 80% with the upper bound set to the average of the FES scenarios and the lower bound from the Pöyry historical analysis which is in line with the evening peak values from the higher demand runs. The higher demand sensitivities result in de-rating factors falling to a similar level to the historical value. French demand peaks around 7pm in the evening (6pm GMT) and is very temperature sensitive. The impact is seen in the big drop in evening peak de-rating factors in the higher demand runs.

Figure 16: French interconnector de-rating factors 2021/22

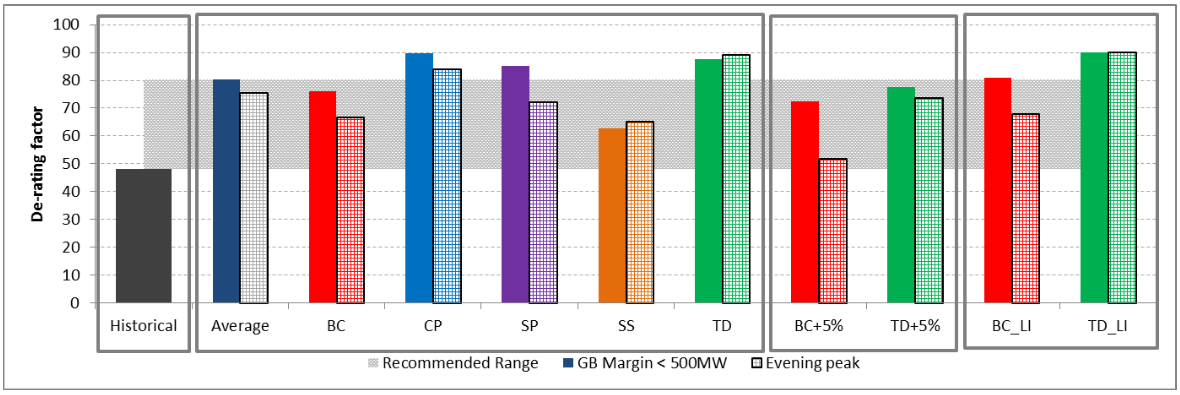


Table 16: French interconnector de-rating factors 2021/22

	Historical Analysis	Average	BC	CP	SP	SS	TD	Demand + 5% BC	Demand + 5% TD	Low Irish Margin BC	Low Irish Margin TD
Low GB Margin	**48**	**80**	76	90	85	63	88	72	78	81	90
Evening Peak	48	75	67	84	72	65	89	52	74	68	90

Ireland:

The proposed de-rating range for Ireland is 29% to 98% with the upper bound set to the average of the FES scenarios and the lower bound from the low Irish margins sensitivity. This range assumes no outages or network constraints. BEIS will make an allowance for outages and constraints in their de-rating factors for each interconnector. Ireland is a single energy market economically but currently there is limited physical links between the north and south. This is expected to be rectified with an additional North/South link which is anticipated to be operational before 2021/22. Ireland was modelled as a single price area so Ireland's North/South constraint had no impact. The modelling assumed that I-SEM would remove the current incentive for flows from GB to Ireland during the peak winter hours. We have assumed that by 2021/22 there will have been several years of market coupling, in which case the Pöyry history should no longer be relevant for setting the low level of the recommended range. However, there is also a risk that intra-day auctions do not take place which will impact on the effectiveness of the market to respond to prices. In those circumstances it may be better to consider the Pöyry history as the lower bound. This year for Ireland the de-rating factor has been calculated using the modelled capacity not export capacity. For Moyle the import capacity was assumed to be constrained. This enables BEIS to adjust for constraints as well as technical de-rating for each interconnector. For comparison with last year's Irish de-rating factor adjusting for constraints would give a range of 19% to 65%.

The FES simulations used Irish demand and generation forecasts that are consistent with ENTSOE figures. This gives a large surplus of generation over demand enabling Ireland to provide very high imports at times of low GB margins. This surplus generation is expensive compared to GB generation so at healthier GB margins it does not contribute as much. This is indicated by the much lower de-rating factors for evening peak hours.

Recently Ireland has shown strong growth in electricity demand which Eirgrid is forecasting to continue in its 2017 All-Island Generation Capacity Statement[33]. Also there will be downward pressure on generation as the Irish capacity market targets 8 hours LOLE through capacity market auctions. Some closures had already been included in the standard Bid3 model runs but there is potential for further reductions if this excess capacity closes by 2021. Therefore we have run two further sensitivities to model the impact of tighter margins in Ireland on interconnector flows: a Base Case run using the median demand forecasts and a Two Degrees sensitivity using the high demand forecasts from the Generation Capacity Statement. In addition we assumed that coal plant expected to close by the mid-2020s had closed by 2020/21. These have been used to set the lower bound of the range for Ireland.

Figure 17: Irish interconnector de-rating factors 2021/22

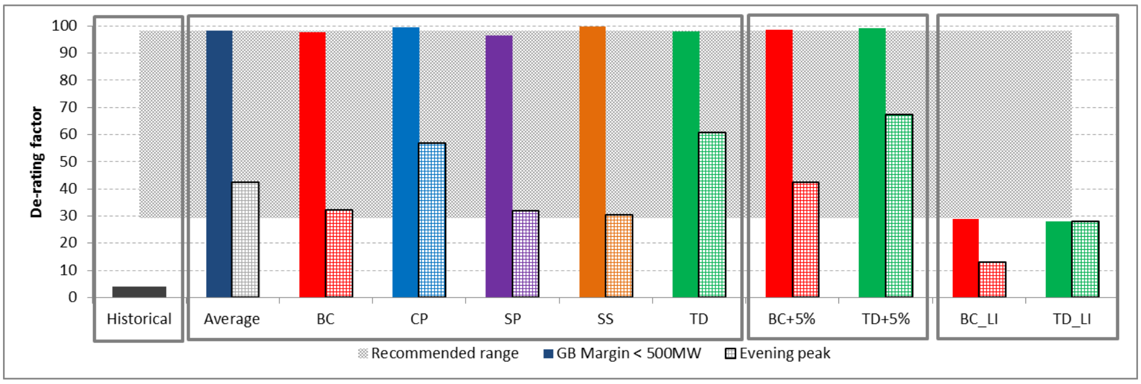


Table 17: Irish interconnector de-rating factors 2021/22

	Historical Analysis	Average	BC	CP	SP	SS	TD	Demand + 5% BC	Demand + 5% TD	Low Irish Margin BC	Low Irish Margin TD
Low GB Margin	4	**98**	98	99	96	100	98	99	99	**29**	28
Evening Peak	4	42	32	57	32	30	61	42	67	13	28

Netherlands:

The proposed de-rating range for the Netherlands is 75% to 81% with the upper bound set to the average of the FES scenarios and the lower bound from the Pöyry historical analysis which is in line with several model runs. The Base Case is slightly lower than the historical average with significant falls in the higher demand sensitivities.

The Netherlands interconnector is normally limited to 1 GW but for short periods can increase to 1.2 GW. Our modelling assumed a capacity of 1 GW but in recent CM auctions the 1.2 GW figure has been applied. We looked at the flows from the model results to see if scaling was required to adjust from a modelled capacity of 1 GW to a CM capacity of 1.2. Flows were mostly either at maximum imports or zero indicating that had we modelled with a higher capacity of 1.2 similar results would have been obtained.

33 http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

Figure 18: Netherlands interconnector de-rating factors 2021/22

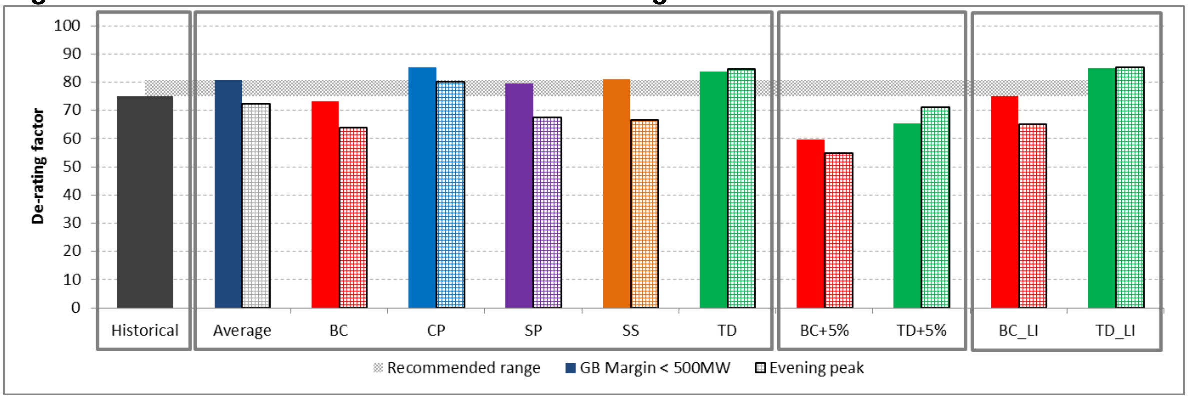


Table 18: Netherlands interconnector de-rating factors 2021/22

	Historical Analysis	Average	BC	CP	SP	SS	TD	Demand + 5% BC	Demand + 5% TD	Low Irish Margin BC	Low Irish Margin TD
Low GB Margin	**75**	**81**	73	85	80	81	84	60	65	75	85
Evening Peak	75	72	64	80	67	66	85	55	71	65	85

Belgium:

The proposed range for Belgium is 65% to 85% with the upper bound set to the average of the FES scenarios and the lower bound from the Pöyry historical analysis, which is in line with the higher demand values.

The Belgium interconnector is not in the Steady State scenario for 2021/22. Despite having a very different capacity margin in Belgium compared to the Netherlands and France all three have similar patterns to the de-rating factors with high values from the FES runs dropping significantly for the higher demand sensitivities reflecting a regional rather than a country level capacity margin driver for interconnector flows.

Figure 19: Belgium interconnector de-rating factors 2021/22

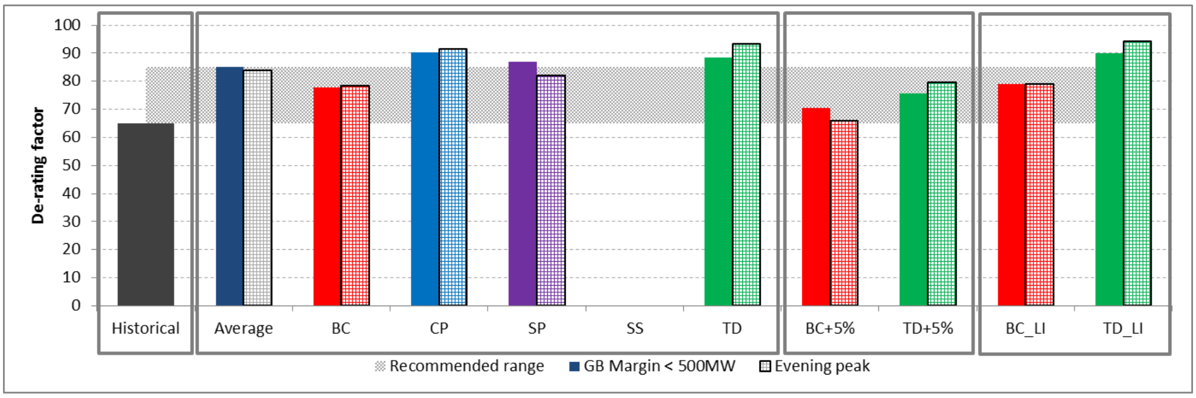


Table 19: Belgium interconnector de-rating factors 2021/22

	Historical Analysis	Average	BC	CP	SP	SS	TD	Demand + 5% BC	Demand + 5% TD	Low Irish Margin BC	Low Irish Margin TD
Low GB Margin	**65**	**85**	78	90	87		89	71	76	79	90
Evening Peak	65	84	78	91	82		93	66	79	79	94

Norway:

The proposed range for Norway is 92% to 99% with the upper bound set to the average of the FES scenarios and the lower bound from the Two Degree 5% demand increase stress test.

Norway only features in Two Degrees. The historical figure is based on historical price differentials between the two markets. However, none of the model runs are at that level as Norway has a healthy surplus of generation over demand which should ensure strong imports when required. Norway has interconnectors with several countries so there could be competition for supplies.

Figure 20: Norway interconnector de-rating factors 2021/22

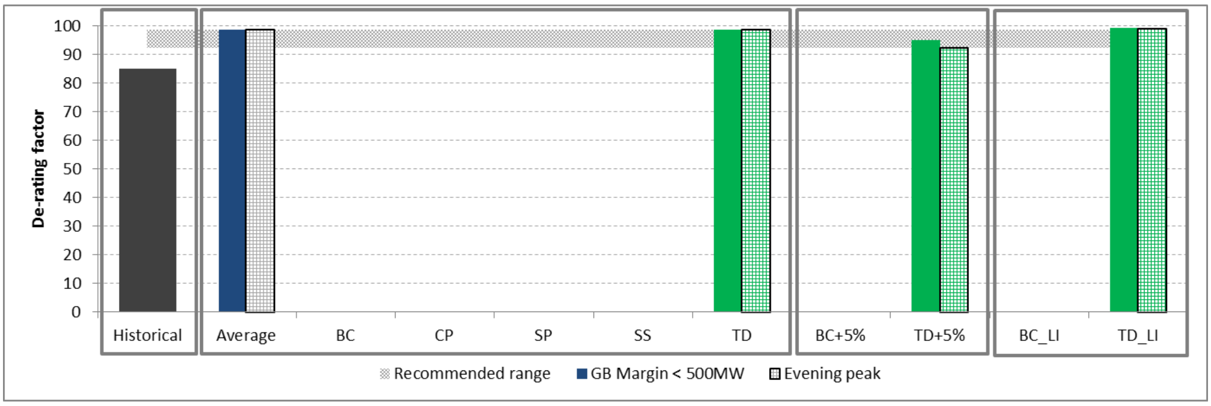


Table 20: Norway interconnector de-rating factors 2021/22

	Historical Analysis	Average	BC	CP	SP	SS	TD	Demand + 5% BC	Demand + 5% TD	Low Irish Margin BC	Low Irish Margin TD
Low GB Margin	85	**99**					99		95		99
Evening Peak	85	99					99		**92**		99

Summary

Table 21 shows the recommended ranges for de-rating factors in 2021/22 for all existing and potential interconnected countries. Note that there are no potential ranges for interconnector de-rating factors for 2018/19 as they are excluded from participating in the auctions for that delivery year.

These de-rating factors are based around the modelling we have undertaken using Bid3, our new pan-European market model, and Pöyry's analysis on historical performance using the methodology specified in the CM rules to inform but not set a lower bound on the recommended range. The top of the de-rating factor ranges are set by the pan-European modelling with Pöyry's analysis of seven historical years setting the bottom of the ranges for all but Ireland and Norway. We have assumed that by 2021/22 the successful introduction of I-SEM could fundamentally change the Irish market meaning the historical market data analysed by Pöyry may no longer be valid. Therefore we have used the lower Irish capacity margin sensitivity, based on the recent All-Island Generation Capacity Statement to set the lower bound. This assumption is not certain and if market coupling does not develop in Ireland then the Pöyry history may be a more appropriate lower bound. Due to the uncertainties of how the Irish market will develop and to ensure a smooth transition we suggest a de-rating factor towards the lower end of the range would be appropriate. This year our Irish range does not include an allowance for the impact of network constraints on the assumption that this is more appropriately allowed for in the adjustments BEIS make to individual interconnector de-rating factors along with technical availability. The bottom of the range for Norway is set to the lowest value from our pan-European modelling because this is higher than the historical analysis which would otherwise set the floor.

Table 21: De-rating factor ranges by country

% 's		France	Netherlands	Ireland	Belgium	Norway
2021/22	High	80	81	98	85	99
2021/22	Low	48	75	29	65	92
	Capacity (GW)	2-3	1.2	0.7	1.0	1.4

5. Results and Recommendation for 2021/22 T-4 Auction

This chapter presents the results for 2021/22 only from the modelling of the scenarios and sensitivities relevant to 2021/22. Results for 2018/19 can be found in chapter 6. Further information on capacity requirements in years out to 2031/32 can be found in section 3.11.

5.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover uncertainty by incorporating ranges for annual and peak demand, DSR, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2017 ECR. The agreed sensitivities to model for 2021/22 cover non-delivery, over-delivery, weather, wind and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Weather Cold Winter (COLD)
- Weather Warm Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non Delivery (NON DEL): 10 sensitivities in 400 MW increments up to 4000 MW (including 3600 MW)
- Over-delivery (OVER DEL): 3 sensitivities in 400 MW increments up to 1200 MW.

5.2 Results

The following table shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All the scenarios and sensitivities modelled take account of capacity market units awarded 15 year contracts in the previous 2018/19 T-4 auction that are now known not to be able to honour their contracts – this totals 1.7 GW (de-rated). In addition, the Base Case and three out of the four Future Energy Scenarios assume that around 100 MW of distributed generation capacity contracted for 2020/21 in previous T-4 auctions is not able to honour its awarded contracts. For Two Degrees a higher level of non-delivery is assumed (300 MW).

Table 22: Modelled de-rated capacities and peak demands - 2021/22

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Slow Progression	SP	46.2	16.8	4.3	0.0	62.9	60.0
Warm Winter	BC_WARM	46.7	15.8	4.3	0.0	62.5	61.3
Low Demand	BC_LOW_DEMAND	47.3	15.9	4.3	0.0	63.1	60.1
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	47.3	17.1	4.3*	1.2	64.4	61.3
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	47.7	16.7	4.3*	0.8	64.4	61.3
Two Degrees	TD	47.8	17.1	4.1	0.0	64.8	61.8
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	48.1	16.3	4.3*	0.4	64.4	61.3
Consumer Power	CP	48.3	16.3	4.3	0.0	64.6	61.8
High Wind	BC_HIGH_WIND	48.3	16.0	4.3	0.0	64.3	61.3
Base Case	BC	48.5	15.9	4.3	0.0	64.4	61.3
Low Wind	BC_LOW_WIND	48.6	15.7	4.3	0.0	64.3	61.3
Non Delivery Sensitivity: -400	BC_NON_DEL_400	48.9	15.5	4.3*	-0.4	64.4	61.3
Non Delivery Sensitivity: -800	BC_NON_DEL_800	49.3	15.1	4.3*	-0.8	64.4	61.3
Cold Winter	BC_COLD	49.6	16.0	4.3	0.0	65.5	61.3
High Demand	BC_HIGH_DEMAND	49.6	15.9	4.3	0.0	65.5	62.5
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	49.7	14.7	4.3*	-1.2	64.4	61.3
Steady State	SS	49.9	15.5	4.3	0.0	65.4	61.4
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	50.1	14.3	4.3*	-1.6	64.4	61.3
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	50.5	13.9	4.3*	-2.0	64.4	61.3
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	50.9	13.5	4.3*	-2.4	64.4	61.3
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	51.3	13.1	4.3*	-2.8	64.4	61.3
Non Delivery Sensitivity: -3200	BC_NON_DEL_3200	51.7	12.7	4.3*	-3.2	64.4	61.3
Non Delivery Sensitivity: -3600	BC_NON_DEL_3600	52.1	12.3	4.3*	-3.6	64.4	61.3
Non Delivery Sensitivity: -4000	BC_NON_DEL_4000	52.5	11.9	4.3*	-4.0	64.4	61.3

Scenario Colour Key
- Two Degrees
- Slow Progression
- Steady State
- Consumer Power
- Base Case

Total derated capacity (GW) =
Capacity to Secure (GW)
+ Outside Capacity Market (GW)

* The previously contracted capacity figure assumes full delivery. Any over or non delivery would be split between plants contracted in previous auctions and plants contracted in future auctions. As such this has accounted for in a separate column

N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with 14 or 15 year contracts secured for 2021/22 in the 2018/19, 2019/20 and 2020/21 T-4 auctions – this capacity is included in the "Outside CM" capacity and is also shown in a separate column. Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity and over-delivery sensitivities by increasing "Outside CM" capacity.

The Slow Progression and 4000 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2020/21 (46.2 GW to 52.5 GW). The Slow Progression scenario has a lower requirement than the other Future Energy Scenarios due to a lower ACS peak demand than the other scenarios combined with higher levels of capacity outside the CM than all scenarios except Two Degrees.

5.3 Recommended Capacity to Secure

Table 22 shows the de-rated capacity required to meet 3 hours LOLE in each model run. However, if capacity was selected based on one model run but in 2021/22 the actual conditions matched a different model run then capacity will have either been over or under secured resulting in an LOLE lower or higher than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select an initial capacity to secure value in 2021/22 taking account of the costs of under or over securing for all potential outcomes.

Links to details on the LWR methodology are provided in the Annex. As per previous ECR analysis, it uses a cost of capacity of £49/kW/yr and an energy unserved cost of £17,000/MWh (consistent with the Government's Reliability Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the LWR calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2021/22 of **50.5 GW** derived from the requirement of the Base Case 2000 MW non-delivery sensitivity. This does not take account of a different clearing price to net CONE resulting from the auction as our recommended capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. It also excludes any capacity secured in earlier auctions for 2021/22 that is assumed in the Base Case.

During the discussions around the potential for non-delivery (ND) sensitivities a question was raised around how sensitive the LWR decision was to the sensitvities included e.g. maximum level of non-delivery. To address this we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in the table below

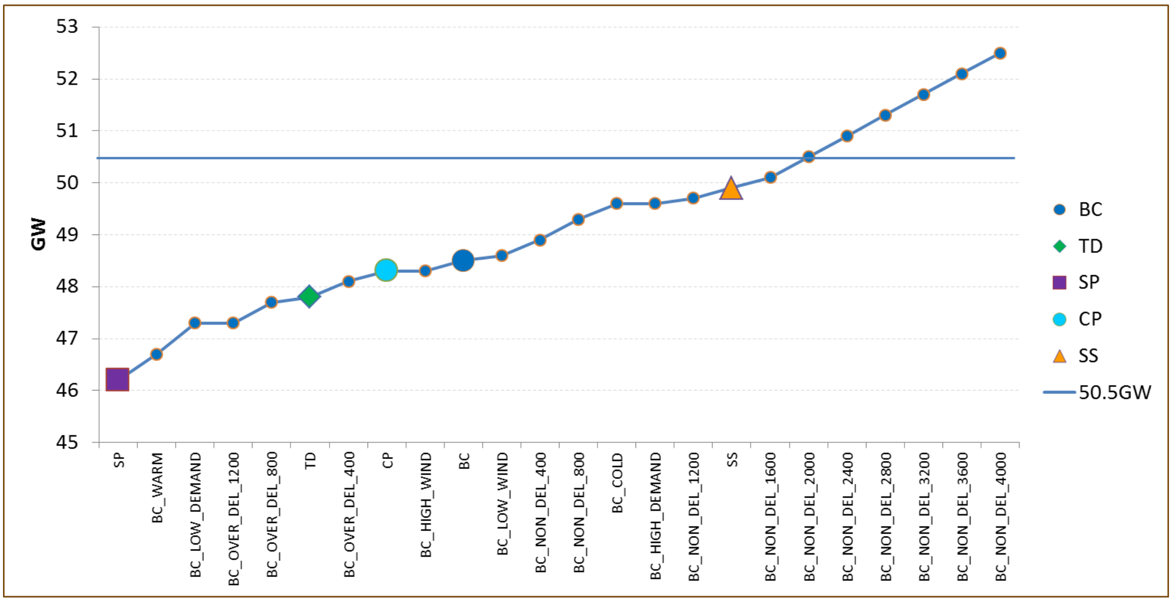
Table 23: Sensitivity of LWR outcome to LWR range

Sensitivities(s) Added (+) or Removed (-)	-SP	-SP - Warm -Low Dem	- 4 GW ND -3.6 GW ND	-4 GW ND	+4.4 GW ND
2021/22 outcome	50.5	50.9	49.7	50.1	50.5

Removing the lowest case (SP) had no impact on the outcome (still 50.5 GW), but removing the 3 lowest cases increased the requirement to 50.9 GW. For a maximum non-delivery of 3.6 GW, the impact on the LWR outcome was a net reduction of 0.4 GW and for a maximum non-delivery of 3.2 GW, the reduction was 0.8 GW, with no change for a maximum non-delivery of 4.4 GW. However, we still believe the most robust maximum non-delivery sensitivity is 4.0 GW to address the considerable risk associated with coal closures, embedded benefits, unproven DSR and battery storage de-rating factors leading to the LWR outcome and our recommendation of 50.5 GW as outlined in this chapter. To set this in context, for the 2018/19 T-4 auction around 4.8 GW of non-delivery has been observed relating to capacity awarded 3 or 15 year contracts that no longer has multi-year contracts.

Figure 21 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR recommended capacity. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note that National Grid's recommendation concentrates on the target capacity alone.

Figure 21: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2021/22



N.B. The points point on this chart represents the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

5.3.1 Covered range

We consider a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2021/22, then the LOLE would be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently/in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the chart, securing a capacity of 50.5 GW would result in 19 out of 24 cases being covered.

5.3.2 Adjustments to Recommended Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by v, w, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW
- Government upon confirming auction parameters to National Grid prior to auction guidelines will determine how much capacity to hold back for the 2021/22 T-1 auction;– wGW

- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine DSR to opt out but remain operational - xGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine distributed generation to opt out but remain operational– yGW*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – zGW*

Therefore, the recommended total capacity to secure through the 2021/22 T-4 auction will be:

- 50.5 GW - v -w - x - y - z

* National Grid's modelling assumes no generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

The auction will select from a range of capacity levels depending on the demand curve, determined by the Government, and the cost of capacity which enters the auction.

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours the demand curve for the auction will result in a capacity from a range around the target capacity. Thus a recommended de-rated capacity of 50.5 GW could result in a differing capacity volume depending on the clearing price set by the marginal capacity. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any issues with this value can be reconciled appropriately in the T-1 auction.

5.3.3 Comparison with 2020/21 recommendation

In our 2016 Electricity Capacity Report, we recommended a capacity to secure for 2020/21 of 49.7 GW, 2 GW above our Base Case requirement of 47.7 GW which assumed 3.5 GW of previously contracted capacity.

In general, when compared to the recommendation for 2020/21 in the 2016 ECR, the 2017 ECR recommendation for 2021/22 assumes slightly higher (0.3 GW) CM-ineligible de-rated capacity at peak. This is a result of the following:

- no change in renewable contribution at peak as slightly higher renewable capacity is offset by lower de-rating factors for some technologies (see Annex for further details)
- 0.8 GW higher assumed levels of previously contracted capacity taking account of 0.1 GW amount of non-delivery assumed in the Base Case (i.e. 4.3 GW in 2017 ECR compared to 3.5 GW in the 2016 ECR)
- 0.5 GW lower levels of assumed opted-out or ineligible (below 2 MW) autogeneration[34]

[34] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW

However there is an increase (1.1 GW) in the capacity requirement due to:

- no change due to the sensitivity range as a slightly higher range of non-delivery sensitivities is offset by the lowest case (Slow Progression) being further away from the Base Case resulting in the same non-delivery sensitivity (2000 MW) setting the requirement
- the de-rated margin required for 3 hours LOLE being 0.4 GW higher
- 1 GW higher peak demand in 2021/22 for the Base Case offset by a 0.3 GW reduction in reserve for largest infeed loss compared to the 2016 Base Case

This analysis highlights the risk of contracted plant defaulting through closures (0.1 GW in the Base Case plus up to a further 4.0 GW in the most extreme non-delivery sensitivity). However we note that by highlighting the risk in this report, some of these closures may be prevented which in turn would reduce the demand curve target in the T-1 auction, which will be reassessed in the 2020 ECR.

The following waterfall chart shows how the original 49.7 GW requirement for the 2020/21 T-4 auction (derived from the 2016 Base Case 2000 MW non-delivery sensitivity) has changed into a recommended requirement of 50.5 GW (derived from the 2017 Base Case 2000 MW non-delivery sensitivity) as a result of the 0.8 GW net increase described above.

Figure 22: Comparison with recommended 2020/21 T-4 requirement in 2016 ECR

6. Results and Recommendation for 2018/19 T-1 Auction

This chapter presents the results for 2018/19 only from the modelling of the scenarios and sensitivities relevant to 2018/19. Results for 2021/22 can be found in chapter 5. Further information on capacity requirements in years out to 2031/32 can be found in Section 3.11.

6.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover uncertainty by incorporating ranges for annual and peak demand, DSR, interconnection and generation with the sensitivities covering uncertainty in single variables. In the modelling we have assumed a net GB interconnector flow of 2100 MW in 2018/19 for the scenarios. Chapter 3 describes the scenarios and sensitivities modelled for the 2016 ECR. The agreed sensitivities to model for 2018/19 cover non-delivery, over-delivery, weather, wind, plant availability, demand and interconnector peak flows:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Weather Cold Winter (COLD)
- Weather Warm Winter (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non Delivery (NON DEL): 7 sensitivities in 400 MW increments up to 2800 MW
- Over-delivery (OVER DEL): 2 sensitivities 200 MW and 600 MW
- 700 MW net GB imports (IC 700IMPORTS)
- 1400 MW net GB imports (IC 1400IMPORTS)
- 2800 MW net GB imports (IC 2800 IMPORTS)
- 3500 MW net GB imports (IC 3500IMPORTS)

6.2 Results

The following table shows the modelling results sorted in order of capacity to secure to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM, the total de-rated capacity and ACS peak demand.

All cases modelled take account of capacity market units awarded contracts for 2018/19 in the previous T-4 auction that are now known not to be able to honour their contracts – this totals 1.7 GW (de-rated).

For transmission connected units contracted in the 2018/19 T-4 auction, the scenarios and sensitivities assume a previously contracted capacity based on de-rated Transmission Entry Capacity (TEC) values which are lower in aggregate than the contracted values in the CM register.

Table 24: Modelled de-rated capacities and peak demands – 2018/19

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Warm Winter	BC_WARM	3.4	59.1	46.5	0.0	62.5	61.7
High Availability	BC_HIGH_AVAIL	3.7	60.3	47.7	0.0	64.0	61.7
Interconnectors 3500 MW Imports	BC_IC_3500IMPORTS	3.7	60.6	46.5	0.0	64.3	61.7
Low Demand	BC_LOW_DEMAND	3.9	59.2	46.5	0.0	63.1	60.5
Slow Progression	SP	4.4	59.4	46.4	0.0	63.8	61.1
Interconnectors 2800 MW Imports	BC_IC_2800IMPORTS	4.4	59.9	46.5	0.0	64.3	61.7
Over Delivery Sensitivity: 600	BC_OVER_DEL_600	4.5	59.8	46.5*	0.6	64.4	61.7
Consumer Power	CP	4.9	59.5	46.5	0.0	64.5	61.7
Over Delivery Sensitivity: 200	BC_OVER_DEL_200	4.9	59.4	46.5*	0.2	64.4	61.7
High Wind	BC_HIGH_WIND	5.0	59.4	46.5	0.0	64.4	61.7
Base Case	BC	5.1	59.2	46.5	0.0	64.4	61.7
Low Wind	BC_LOW_WIND	5.3	59.1	46.5	0.0	64.4	61.7
Steady State	SS	5.4	59.0	46.5	0.0	64.4	61.7
Non Delivery Sensitivity: -400	BC_NON_DEL_400	5.5	58.8	46.5*	-0.4	64.4	61.7
Non Delivery Sensitivity: -800	BC_NON_DEL_800	5.9	58.4	46.5*	-0.8	64.4	61.7
Interconnectors 1400 MW Imports	BC_IC_1400IMPORTS	6.0	58.4	46.5	0.0	64.4	61.7
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	6.3	58.0	46.5*	-1.2	64.4	61.7
Two Degrees	TD	6.4	58.6	45.0	0.0	65.0	62.0
Cold Winter	BC_COLD	6.4	59.3	46.5	0.0	65.6	61.7
High Demand	BC_HIGH_DEMAND	6.4	59.3	46.5	0.0	65.7	62.9
Interconnectors 700 MW Imports	BC_IC_700IMPORTS	6.6	57.8	46.5	0.0	64.4	61.7
Low Availability	BC_LOW_AVAIL	6.6	58.0	45.2	0.0	64.7	61.7
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	6.7	57.6	46.5*	-1.6	64.4	61.7
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	7.1	57.2	46.5*	-2.0	64.4	61.7
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	7.5	56.8	46.5*	-2.4	64.4	61.7
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	7.9	56.4	46.5*	-2.8	64.4	61.7

Scenario Colour Key
Two Degrees
Slow Progression
Steady State
Consumer Power
Base Case

Total derated capacity (GW) =

Capacity to Secure (GW)
+ Outside Capacity Market (GW)

* The previously contracted capacity figure assumes full delivery. Any over or non delivery would be split accounted for in a separate column

N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts secured for 2018/19 in the 2018/19 T-4 auctions – this capacity is included in the "Outside CM" capacity and is also shown in a separate column. Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity and over-delivery sensitivities by increasing "Outside CM" capacity.

The warm winter and 2800 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2018/19 (3.4 GW to 7.9 GW).

6.3 Recommended Capacity to Secure

The table above shows the capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run but in 2018/19 the actual conditions matched a different model run then capacity will have either been over or under secured resulting in an LOLE higher or lower than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology agreed with BEIS and the PTE has been used to select a recommended capacity to secure value in 2018/19 taking account of the costs of under or over securing for all potential outcomes.

Links to details on the LWR methodology are provided in the Annex. As per previous ECR analysis, it uses a cost of capacity of £49/kW/yr and an energy unserved cost of £17,000/MWh (consistent with the Government's Reliability Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to secure for 2018/19 of **6.3**

GW derived from the requirement of the Base Case 1200 MW sensitivity. This does not take account of a different clearing price to net CONE resulting from the auction as our recommended capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also excludes any capacity secured in the T-4 auction for 2018/19 assumed in the Base Case.

During the discussions around the potential for non-delivery (ND) sensitivities a question was raised around how sensitive the LWR decision was to the sensitvities included e.g. maximum level of non-delivery. To address this we ran the LWR tool with some of the highest and lowest cases removed. The results from this are shown in the table below.

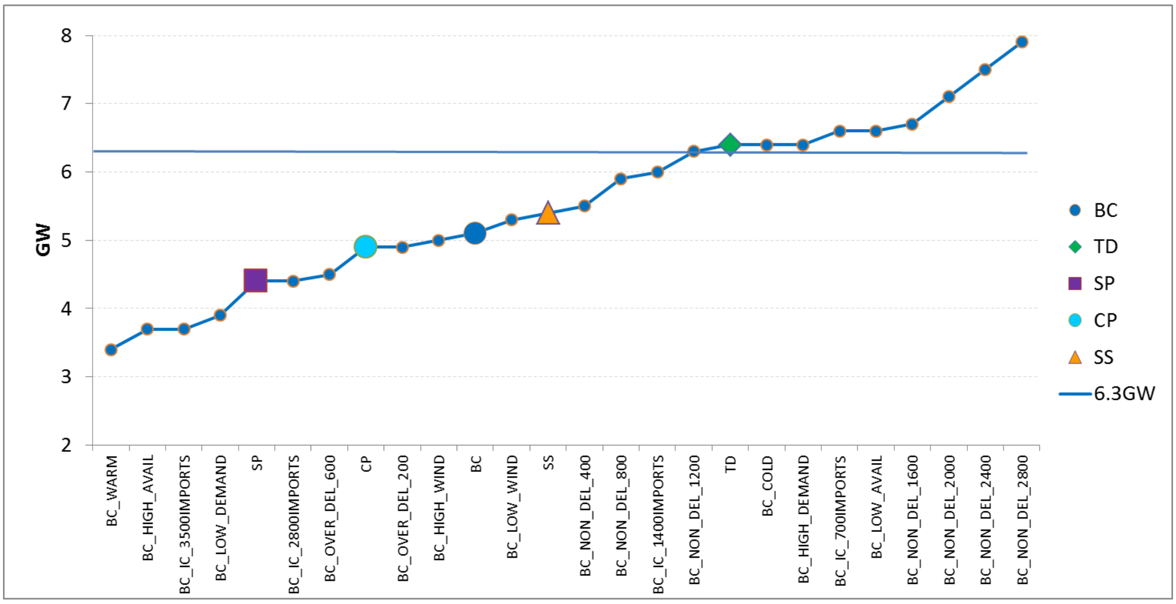
Sensitivity of LWR outcome to LWR range

Sensitivities(s) Removed (-)	-Warm	-Warm - High Avail. -3500 Imports	-2.8GW ND -2.4GW ND	-2.8 GW ND
2018/19 outcome	6.3	6.4	5.5	5.9

Removing the lowest case (Warm Winter) had no impact on the outcome (still 6.3 GW), but removing the 3 lowest cases increased the requirement slightly to 6.4 GW. For a maximum non-delivery of 2.4 GW, the impact on the LWR outcome was a net reduction of 0.4 GW and for a maximum non-delivery of 2.0 GW, the reduction was 0.8 GW. However, we still believe the most robust maximum non-delivery sensitivity for 2018/19 is 2.8 GW to address the considerable risk associated with coal closures, embedded benefits, unproven DSR and battery storage de-rating factors leading to the LWR outcome and our recommendation of 6.3 GW as outlined in this chapter.

The following chart illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity. Note that this concentrates on the target capacity alone.

Figure 23: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2018/19



N.B. The points point on this chart represents the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

6.3.1 Covered range

We consider a scenario or sensitivity is covered by the capacity secured if the Loss of Load Expectation (LOLE) is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2018/19, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently/in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the above chart, securing a capacity of 6.3 GW would result in 17 out of 26 cases being covered.

6.3.2 Adjustments to Recommended Capacity

The recommended capacity in this report (if it became the recommended capacity) would not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the T-1 auction target, a number of adjustments to the indicative figure or range may need to be made (e.g. denoted by v, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine DSR to opt out but remain operational - xGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine distributed generation to opt out but remain operational– yGW*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine large scale generation to opt out but remain operational or adjustment due to contracted plants with different closure assumptions to the Base Case – zGW*

Therefore, the recommended capacity to secure through the 2018/19 T-1 auction could be:

- 6.3 GW - v - x - y - z

*National Grid’s modelling assumes no generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

The auction will select from a range of capacity levels depending on the demand curve, determined by the Government, and the cost of capacity which enters the auction.

A recommended de-rated capacity of 6.3 GW could result in a differing capacity volume being secured depending on the clearing price set by the marginal capacity and the shape of the demand curve. The tolerances are set by BEIS in order to limit gaming opportunities.

6.3.3 Comparison with 2018/19 recommendation

In our 2014 Electricity Capacity Report, we recommended a capacity to secure for 2018/19 of 53.3 GW of which the Secretary of State decided to hold back 2.5 GW for the 2018/19 T-1 auction leaving a target capacity of 50.8 GW for the T-4 auction. Following pre-qualification, the 2018/19 T-4 auction target was reduced by 2.2 GW to 48.6 GW to take account of 2.1 GW of transmission connected capacity that was opted out but operational in 2018/19 and 0.1 GW of long-term STOR opted out capacity. In the latest T-4 auction CM register for 2018/19, there is just over 47.5 GW of non-terminated awarded capacity, a reduction of over 1.7GW from the 49.3 GW contracted in the T-4 auction.

In general, when compared to the analysis for 2018/19 in the 2014 ECR that ultimately led to the 2.5 GW set aside by the Secretary of State for the T-1 auction, the 2017 ECR recommendation for 2021/22 assumes higher (4.1 GW) ineligible capacity at peak. This is a result of the following:

- 2 GW higher non-CM capacity comprised of higher renewables contribution at peak (see Annex for breakdown) in part due to the new offshore power curve introduced in the 2016 ECR and higher levels of assumed opted-out or ineligible (below 2 MW) autogeneration[35]
- 2.1 GW higher assumed imports at peak in the Base Case

However the reduction (compared to the 2014 ECR recommendation) in the T-1 CM-eligible capacity requirement due to higher levels of ineligible capacity is more than offset by the 7.9 GW net increase in capacity requirement due to:

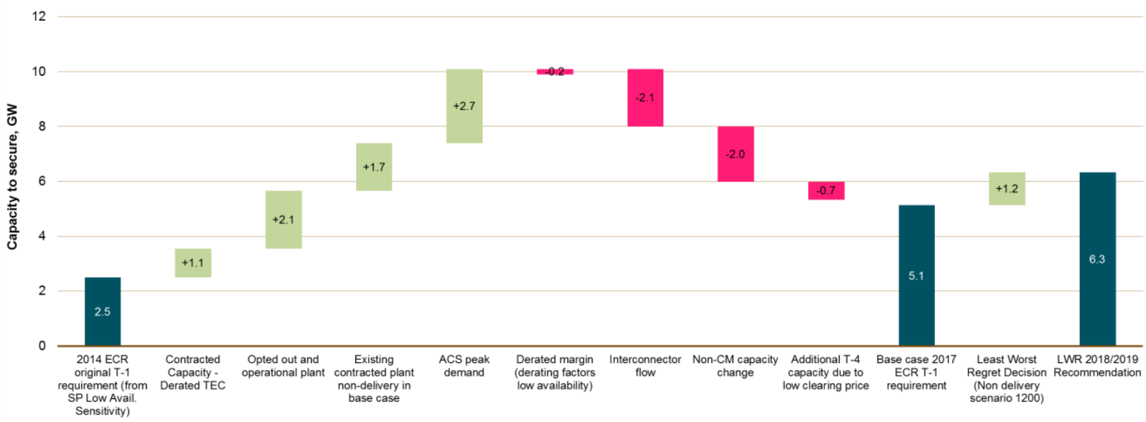
- a wider range of sensitivities (including non-delivery) that increases the requirement in the LWR analysis by 1.2 GW
- known non-delivery, totalling 1.7 GW in 2018/19 in the Base Case.
- the remaining contracted capacity in the T-4 auction being 1.1 GW greater than de-rated TEC
- 2.1 GW "opted out but operational" plant closing or opting in to the CM
- 2.7 GW higher peak demand in 2018/19 for the Base Case compared to the 2014 Slow Progression Low Availability sensitivity that set the 2014 ECR recommendation (see below)
- Reductions in requirement from over-securing in the 2018/19 T-4 auction by 0.7 GW and a 0.2 GW lower de-rated margin required for 3 hours LOLE.

The analysis highlights the risk of contracted plant defaulting through closures (1.7 GW of known non-delivery in the Base Case plus up to a further 2.8 GW in the most extreme non-delivery sensitivity). However we note that by highlighting the risk in this report, some of the non-delivery may be prevented.

The following waterfall chart shows how the original 2.5 GW set aside for the 2018/19 T-1 auction (derived from the 2014 Slow Progression Low Availability sensitivity) has changed into a recommendation of 6.3 GW (derived from the 2017 Base Case 1200 MW non-delivery sensitivity).

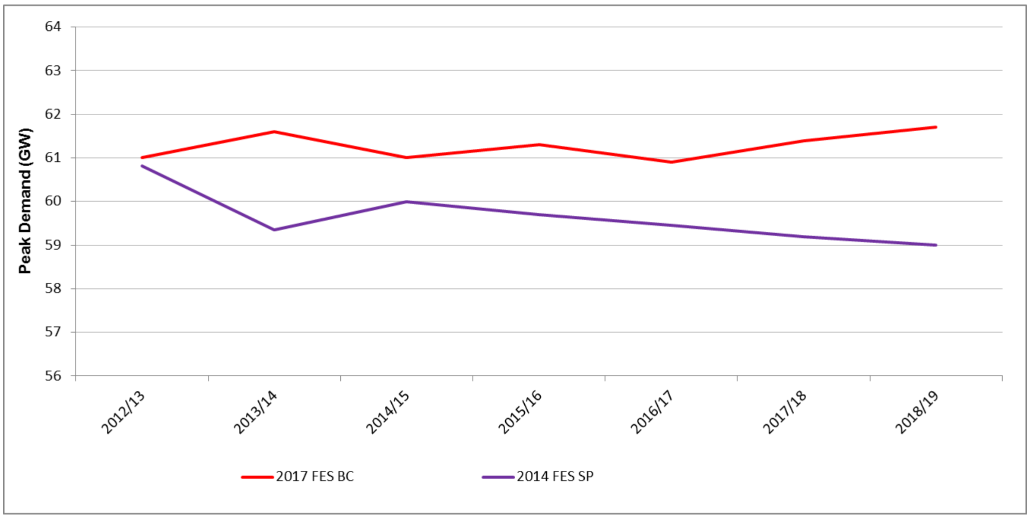
[35] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW

Figure 24: Comparison with original 2018/19 T-1 requirement (de-rated)



Out of all of the changes since the 2014 ECR highlighted above, the largest change (2.7 GW) relates to the increase in peak demand. The following chart compares the underlying ACS peak demand in the 2017 Base Case to the underlying ACS peak demand in the 2014 Slow Progression scenario over the period from 2012/13 to 2018/19 which illustrates that the 2017 Base Case peak demand has (up to 2016/17) and is projected to remain relatively flat while the 2014 Slow Progression peak demand was projected to decline over the period driven through greater energy efficiency measures.

Figure 25: Peak Demand Comparison (2017 ECR v 2014 ECR)



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The differences in the peak demands projected for 2018/19 between 2014 and the 2017 are largely the result of differences in the modelled split between transmission (unrestricted GB National) demand and demand met by distributed generation (including sub 1MW). The table below highlights that for 2018/19 in the 2017 Base Case, the demand met by distributed generation is much higher (5.6 GW) than that assumed in 2014 whereas the transmission demand is lower (2.9 GW) in 2017 than in 2014.

Table 25: Modelled split of peak demand met by transmission & distributed generation

Peak demand for 2018/19 GW	2014 Slow Progression	2017 Base Case
Unrestricted GB National demand	53.6	50.7
Demand Met by Distributed Gen.	5.4	11.0
Total GB underlying demand	**59.0**	**61.7**

This highlights the need to continue to develop our methodologies to enhance our knowledge of particularly distributed connected generation and its output at times of peak demand. The letter written under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[36].

[36] To be published at https://www.emrdeliverybody.com/cm/home.aspx

A. Annex

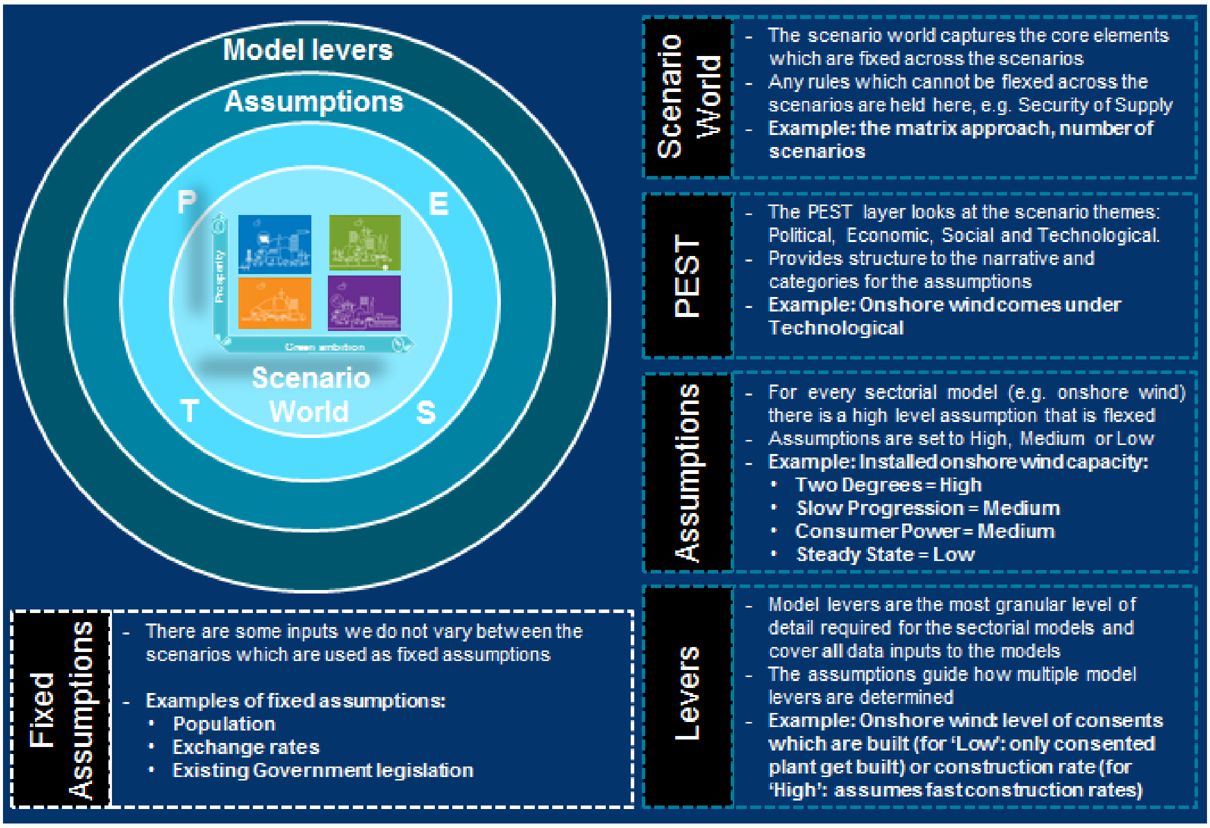
A.1 Future Energy Scenario Method

Through our continuing stakeholder engagement for FES 2017 we have consulted with 391 organisations and individuals, up from 362 for FES 2016. For the details of this engagement and how we have used this to help us shape FES 2017 see our Stakeholder Feedback document[37]. From this feedback we have maintained four scenarios for FES 2017 and our scenario framework approach for FES 2016. There have been some significant changes from FES 2016, notably the retiring of the scenario names ‘Gone Green’ and ‘No Progression’:

Scenario Framework

We use the scenario framework to set out a structured approach which provides a single reference to group all the inputs and assumptions that we use to build our scenarios, see Figure 26 below. There has been strong support from our stakeholders to continue this approach from FES 2016:

Figure 26: 2017 Scenarios Framework



Central to the scenario framework is the scenario world. This effectively captures the core elements which are fixed across the scenarios: the matrix, the axes and fixed rules (e.g. security of supply). The next layer introduces the scenario themes:

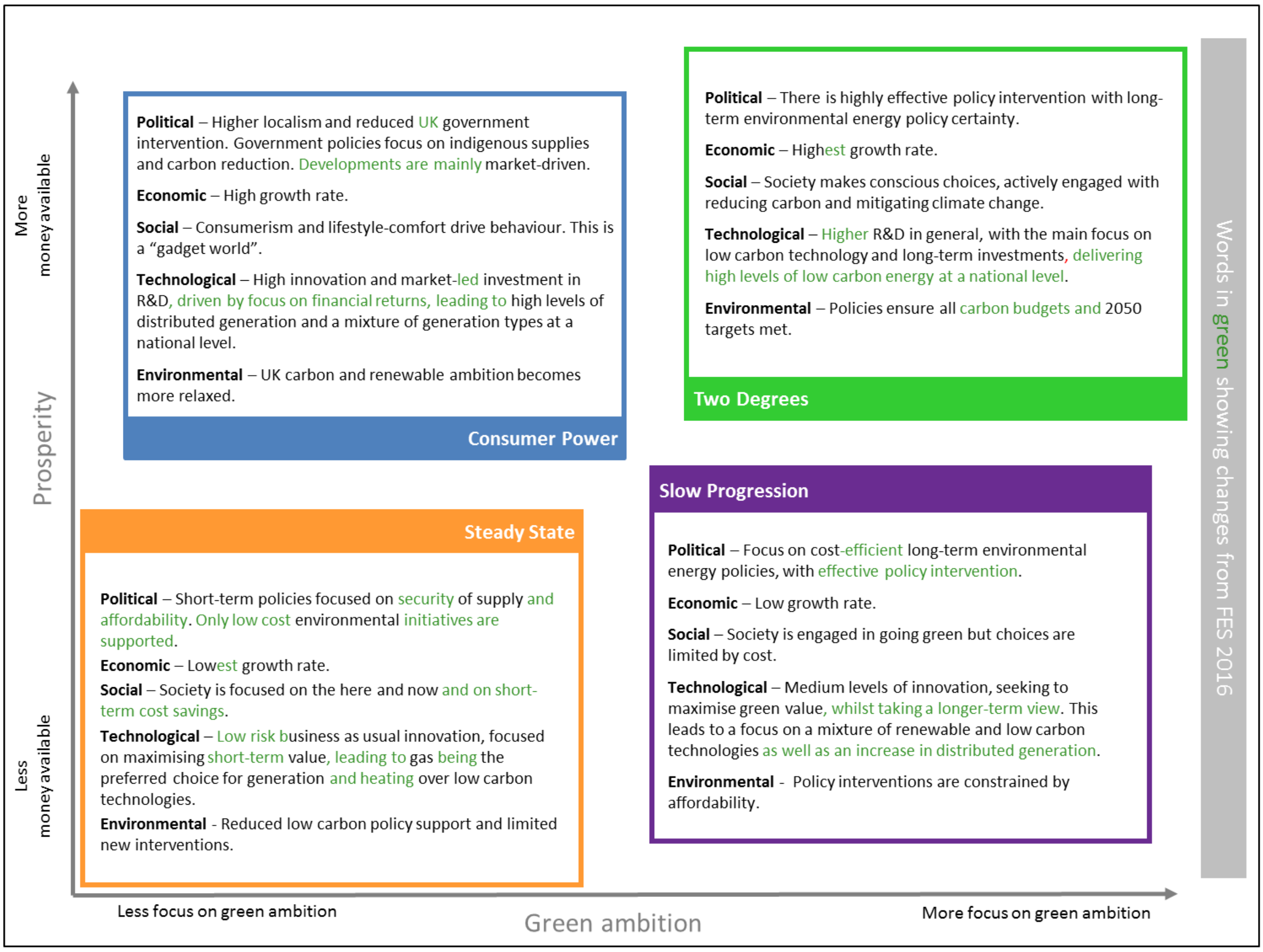
[37] http://fes.nationalgrid.com/media/1195/stakeholder-feedback-document-fes-2017.pdf

Political, Economic, Social and Technological (PEST) which are used to structure the scenario narrative and model assumptions. Sitting beneath each theme are all of the assumptions that feed into the scenarios. Each assumption broadly aligns to sectorial models (e.g. onshore wind) and will be set at high, medium or low for each of the four scenarios. The final layer of the framework is the specific model levers which are the detailed granular inputs into the analysis – these cover all inputs to all the models used to produce the FES.

FES 2017

The matrix in Figure 27 below provides a high level overview of FES 2017. Stakeholder feedback over the past year shows strong support for keeping the four scenarios in the 2x2 matrix, with the ‘prosperity’ and ‘green ambition’ axes. We have made selective updates to the scenario narrative (shown in green in the diagram below) to provide further clarity and to reflect the key changes described below.

Figure 27: 2017 Scenarios Matrix



Key changes for FES 2017

We continually look to review our scenarios and ensure they are credible and fit for purpose. Our research, intelligence and stakeholder feedback over the past year has led to the following key changes:

Retiring the names ‘Gone Green’ and ‘No Progression’:

These names have been retired to more accurately reflect the scenarios. The name Gone Green has remained the same since the scenario was first introduced in 2011, but the scenario itself has evolved significantly over the years. There has been a shift from a focus on renewable technologies to low carbon technologies, and in FES 2016 the scenario no longer met the 2020 renewables target, whilst still meeting the 2050 carbon reduction target. The name Gone Green is replaced by **Two Degrees** and the scenario will continue to be our core scenario that meets the 2050 carbon reduction target (none of the other scenarios will meet this target without targeted intervention). The name **Two Degrees** signifies that the scenario is consistent with the UK carbon budgets and the 2050 target which is the UK’s contribution to the Paris Agreement of seeking to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels.

Our stakeholders have told us they do not think the name No Progression accurately reflects the scenario. The name could suggest ‘no change’, despite there being some business as usual progress and innovation. The new name, **Steady State**, better reflects the scenario which continues to represent a world where current levels of progress and innovation are reflected out to 2050.

Repositioning the scenarios on the axes: We have repositioned the scenarios on the axes in the scenario matrix (see Figure 27 above). This reflects how we have distributed the wider range of economic growth forecasts across the four scenarios - **Two Degrees** being more prosperous than **Consumer Power** and **Slow Progression** being more prosperous than **Steady State**. The repositioning also reflects differences between the scenarios in the level of green ambition.

Impact of the UK leaving the European Union (EU): Our analysis and stakeholder feedback has shown uncertainty around the impact of the UK leaving the EU. We model this by using a wider range of economic growth forecasts for FES 2017, two higher growth and two lower growth forecasts, instead of only one high and one low forecast in 2016.

Reflecting trends in distributed generation: As in previous years, all of our scenarios will consider energy demand and supply with a whole system view. To reflect recent trends in the electricity market, two (**Slow Progression** and **Consumer Power**) of our four scenarios for 2017 have high levels of distributed generation growth (compared to one last year, **Consumer Power**), with the other two scenarios featuring more moderate growth rates of distributed generation to reflect uncertainty. This has also been supported by stakeholder views.

A.2 Demand Methodology

The demand projections are developed using in-house analysis which has used stakeholder feedback to inform it. This feedback data is collected via the FES consultation process as well as in house analysis. Annual demands can be considered with the following breakdown:

- Domestic
- Industrial
- Commercial
- Transport
- Other/Sundry

Domestic

The domestic demand is created by using a bottom up method. Each of the component parts of the sectors demand is modelled individually. Where there is a history then this is used as the starting point for the modelling. If a component part is novel then research, projects' outcomes and proxy data are applied as appropriate. These components are listed below and each is projected individually which, when aggregated, form domestic demand for each scenario.

- **Appliances, including lighting:** A regression trend method flexed by the application of primary assumptions and appliance number caps. We have assumed energy efficiency gains in all our scenarios but with varying degrees depending on the scenario.

- **Resistive heat:** A new methodology has been applied where we use the thermal efficiency of the housing stock rather than just the insulation to inform our modelling. In our greenest scenario the average household thermal efficiency will be much improved on today's average. We see heat pumps as being the main alternative sources for heating as opposed to gas in our greener scenarios.

- **Resistive hot water:** the current hot water electrical heat demand comes from published statistics[38]. Due to the projected increase in heat pumps and the increase in the housing stock we expect the power demand for hot water to rise.

- **Heat pumps:** We see heat pumps as being the main source of non-gaseous heating. In order to decarbonise heating there is now a more complex interplay of different types of heat pumps with air-source and hybrid heat pumps vying for dominance. Energy efficiency improvements are assumed annually based on manufacturer engagement feedback.

- **Consumer Flexibility –** deterministic modelling using a smart meter roll out profile and project outcome data, such as the Customer-Led Network Revolution[39]. This year a new approach has been taken to consumer engagement. This includes extrapolating the series of Ofgem's retail market

[38] https://www.gov.uk/government/statistics/energy-consumption-in-the-uk
[39] http://www.networkrevolution.co.uk/

review data, to forward project customer engagement rates. This percentage is applied to the underlying domestic demand.

Industrial

Economic data provided by Oxford Economics in December 2016 was used to create four economic cases for GB economic growth. Retail energy prices are generated from our wholesale energy prices and then benchmarked against BEIS' scenarios.

The model examines 24 sub-sectors (Industrial and commercial) and their individual energy demands, giving a detailed view of GB demand, and uses an error correcting model to produce projections for each sub-sector individually. The model then has two further modules to investigate the economics of increasing energy efficiency (e.g. heat recovery) and new technologies such as onsite generation (e.g. CHP) or different heating solutions (e.g. biomass boilers).

These modules consider the economics of installing particular technologies from the capital costs, ongoing maintenance costs, fuel costs and incentives. These are used along with macro-financial indicators such as gearing ratios and internal rate of return for each sub-sector to consider if the investment is economical and the likely uptake rates of any particular technology or initiative. This allows us to adjust the relative cost benefits to see what is required to encourage uptake of alternative heating solutions and understand the impact of prices on onsite generation.

Commercial

The same approach as described in the paragraphs above (in the industrial section) has been adopted this year.

Transport

- Electric Vehicles – a deterministic approach profiling purchase rates of different types of electric vehicles based on stakeholder feedback. This is combined with statistics on journey length in order to assess the associated electrical demand. This year we have also incorporated the concept of vehicle sharing and autonomous vehicles.
- Rail – three projections are applied to the rail demand based on stakeholder feedback. One is a continuation of historical growth (low) and the others are an enhanced growth rate and a mid-range value.
- Natural Gas Vehicles - a deterministic approach is applied based on research of other countries natural gas vehicle developments.

Other/Sundry

These are the demand components which do not fall directly into the categories above. For example, losses which are a function of the total demand figure, interconnector flows or micro-generation which is required in order to translate the FES total energy demand into a distribution or transmission demand definition.

Peak Demands

Once the assessment of underlying annual demand is created a recent historical relationship of annual to peak demand is applied. This creates an underlying peak demand to which peak demand components that history cannot predict are added.

For example, electric vehicle charging or heat pump demand at times of peak demands on the transmission system.

For each of the scenarios we also applied a consumer engagement factor which ranges from 16% up to 85% in our greenest scenario.

The overlays to peak demand are;

- Electric vehicles: Based on the projected numbers, the potential user groups are assessed, how and when they could be charging (constrained and unconstrained), and data from recently published trials are incorporated. This year we have also increased the size of charger units from 3.5 kW to 7 kW.
- Heat pumps: The number of heat pumps and heat demand, data from manufacturers, and trial within day profiles combined with performance statistics and historical weather trends are used to determine the electrical heat demand at peak.
- Losses: As with annual demand, this is a function of total peak demand.
- Industrial & Commercial Demand Side Response: Created using desktop research and assumptions of future efficiency improvements, consumer engagement and information technology improvements.
- Domestic peak response – as with annual demand this starts with the smart meter roll out numbers, project outcome data and perceived customer engagement rates. From this results a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

Calibration

Both annual and peak demands are calibrated. Annual demands are calibrated to the previous year's historical annual demand figures as published by BEIS. Peak demand is calibrated with weather corrected metered transmission demand.

Results

The results of the described methods provided are defined and shown in the Annex (Section A.5.1). For a more detailed description of the methodology and FES scenarios please refer to the FES document or its workbook[40]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

[40] http://fes.nationalgrid.com/fes-document/

A.3 Generation Methodology

The power supply transmission backgrounds use a rule based deterministic approach. An individual assessment of each power station (at a unit level where appropriate) was completed, taking into account a wide spectrum of information, analysis and intelligence from various sources.

The scenario narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. Each power station was placed accordingly within their technology stack.

The placement of a power station was determined by a number of factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that particular power station, are also taken into account. The contracted background or Transmission Entry Capacity (TEC) Register[41] provides the starting point for the analysis of power stations which require access to the National Electricity Transmission System (NETS). It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted background provides the basis for the majority of the entries into the generation backgrounds, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre connection agreement) are also taken into account.

For power generation connecting to the distributed system (including capacity < 1 MW), alternative sources of data will be used as the starting point for assessment, such as the Ofgem Feed In Tariffs register or BEIS Planning Base.

The generation backgrounds are then built up to meet the Reliability Standard in line with the FES Framework (i.e. all scenarios ensure security of supply is met).

A.3.1 Contracted Background

This contracted background provides a list of power stations which have an agreement to gain access rights to NETS; now and in the future. It provides valuable up to date information regarding any increase or decrease to a power station Transmission Entry Capacity which provides an indication of how a particular plant may operate in future years. This is then overlaid with market intelligence for that particular plant and/or generation technology type.

A.3.2 Market Intelligence

This section covers how market intelligence gathered through stakeholder engagement along with more general information is used to help determine which generation is likely to connect during the FES study period.

Developer Profile

This information relates to the developer of a certain project, or portfolio of projects, and provides an insight into how and when these projects may develop. Examples of information taken into account under this area are:

- Is the developer a portfolio player who may have a number of potential projects at different stages of the process in which case intelligence is

[41] http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/

gathered on the developers "preferred" or "priority" projects, or is it a merchant developer who is looking to become active within the electricity market?
- How active is the developer in the GB electricity market?

Technology

This area looks specifically at future and developing technologies to gauge how much of a part certain emerging generation types may play in the generation backgrounds. Examples of information taken into account in this area are:

- At what stage of development or deployment is the technology, e.g. has the technology been proven as a viable source of electricity generation?
- Have there been trial/pilot projects carried out as with technologies such as wave and tidal?
- Has there been a commercial scale roll-out of the technology following successful trial/pilot schemes?
- Is there Government backing and support for the new technology?
- Are there any industry papers or research regarding the roll-out of new technologies in terms of the potential scale of deployment should the technology be proven?

Financial Markets

Information relating to the financial markets is also a consideration in terms of how easy it will be for the developer to raise the capital to fully develop the project e.g. off the balance sheet or via the capital markets.

Consideration is also given to the economics for different types of generation, in terms of electricity wholesale prices, fuel prices and the impact of the carbon price (i.e. clean dark and spark spreads) which may impact the operational regime on a technology and/or plant-specific basis.

A.3.3 FES Plant Economics

This area is a key feed-in to the power generation backgrounds and explores economic viability and how a particular plant or group of plants could operate in the market now and in the future. Analysis into the Short Run Marginal Cost (SRMC) of the existing power station fleet has been a focus of the 2017 analysis.

The results of the analysis inform the transmission generation backgrounds, particularly plant closure profiles.

A.3.4 Project Status

The project status is especially important when determining at what point in time a new generator may become operational. For a new plant, factors such as whether a generator has a signed grid connection agreement, where in the consenting process the project is and if the developer of the project has taken a financial investment decision are all key in determining the timing of future projects. Depending on the project status, a likelihood rating is then given to the plant. For example, if the plant only has a grid connection agreement and no consents it will be ranked far lower than a power station that has these or is physically under construction. For existing power generation, it is important to consider any decommissioning dates (for example nuclear), potential replanting of stations (for example wind) and the lifecycle for the particular technology.

A.3.5 Government Policy and Legislation

It is important that the power supply scenarios reflect Government policy and initiatives for particular generation projects and/or technology. This may be in the form of financial support for selected technologies that are targeted and developed, such as the low carbon technologies; nuclear, offshore wind, marine energy and CCS. Alternatively it could be in the form of market-wide mechanisms to develop, for example flexible generation, such as the Capacity Market.

Energy legislation enacted at the European and national level will impact which power supply sources are developed and connected to the NETS. For example, renewable energy targets are intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, therefore making it very likely in FES scenarios with a high green ambition that the NETS will experience much more intermittent renewable capacity. Another example is the plant that may have to be modified to comply with environmental directives, such as the Industrial Emissions Directive (IED) and the Medium Combustion Plant Directive (MCPD). This legislation places restrictions on the number of running hours for fossil fuel power generation plants with regard to the harmful waste gases that they emit, unless investments are made to reduce this impact, and will affect decisions on whether to invest in new plants or maintain existing facilities.

A.3.6 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered. The 2017 power generation backgrounds are developed to both meet demand and to reflect the implementation of the GB Reliability Standard of 3 hours Loss of Load Expectation (LOLE) / year. In the early years of the FES study period, the generation backgrounds were driven by relatively more granular intelligence and therefore LOLE could potentially vary significantly year to year within this period. This can, for instance, be caused by plants without CM contracts staying open.

As a result, the LOLE calculation within the generation backgrounds has been slightly amended to ensure that it is consistent with the implementation of the CM Reliability standard and any short term market perturbations around this metric. The modelling has also now moved from a pure transmission focus (i.e. assessing LOLE based on transmission-level generation against transmission-level demand) to a more whole-system approach whereby all generation (including units connected to the distribution networks) is assessed against total underlying demand.

A.4 EMR/Capacity Assessment Development Projects Matrix

The table below lists all the development projects and their respective scores. Based on the process described in section 2.5.1, only projects 1-18 attracted high enough scores to qualify for this year’s analysis.

Table 26: Development Projects Matrix

Development Project Description	Materiality*	Resources*	Priority*	Total
1)- Review the role of the National Grid Capacity Assessment (CA) model for the CM delivery years	9	-3	15	21
2)- Update the Reading University tool to extract wind data from NASA's website	9	-4.5	15	19.5
3)- Improve demand forecasting via analysis of small-scale data and DSR (PTE recommendation 22)	9	-6	15	18
4) Investigate separate de-rating factor for battery storage (#This project was later reprioritised over project 17 using change control process, with agreement for delivery in summer)	**3**	**-6**	**4**	**1#**
5)- Develop project plan, agree priorities and implement question management process	9	-8	15	16
6)-Update de-rating factors for small scale CM/non-CM technologies	9	-9	15	15
7)-Update the CA model to bring it in line with the CM market and demand definition	9	-9	15	15
8)-Reviewing the international implementation / interpretation of current electricity Security of Supply standards	8	-9	13	12
9)-Development of Pan European market Model (PTE recommendation 13)	8	-9	13	12
10)-Review and quantify Dynamic Dispatch Model (DDM) developments for 2017 ECR. Implement DDM Developments for 2017 ECR (if required)	7	-6	9	10
11)-Revise the wind history code such that previous wind history files are not recreated	6.5	-4.5	7	9
12)- Review of overall modelling strategy and consider a range of options (DDM plus LWR etc.) to incorporate probabilities or weightings of sensitivities into the process for determining the recommended capacity to secure. (PTE Recommendation 25)	6	-7	9	8
13)- Analysis of VoLL cost & risk around reliability standards (PTE Recommendation 24, This project was led by BEIS and Ofgem with NG providing support)	7	-9	9	7
14)-Review wind power curves (including potentially a new power curve for large offshore wind turbines > 4MW)	6	-6	7	7
15)-Review content of 2017 Electricity Capacity Report (ECR)	5	-3	5	7
16) - Consider ways to take account of the probability of all forms of capacity fulfilling contract. (PTE Recommendation 17)	6.5	-7	7	6.5
17)- Develop better "ready reckoners" for SoS analysis to enable impact of plant closures etc. to be estimated quickly without the need to rerun the main SoS models (#This project was de-prioritised by project 4 using change control process). Project scope is agreed to deliver this project in summer'17.	**9**	**-7**	**15**	**17#**
18)-Analysis (including risks) of the policy changes and its impact on plants already holding capacity agreement for distributed generation. Analysis of the potential impact of Ofgem "embedded benefits" consultation was undertaken to support non-delivery sensitivities. (PTE Recommendation 21)	6	-7	7	6

19)-Further analysis on how plant specific costs such as Transmission Network Use of System (TNUoS) charges could impact size of coal plant non-delivery risk to improve understanding around the likelihood of honouring of capacity contracts or potential availability of coal plants in future auctions (PTE Recommendation 20)	5.5	-6.5	7	6
20) - 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. (PTE Recommendation 23)	6	-9	9	6
21)-Collect information on how Distribution Network Operators (DNOs) plan to respond to Demand Control orders to ensure security of supply.(PTE Recommendation 16)	6	-8	7	5
22)-Review how we model conventional generation uncertainty	7	-9	7	5
23)-Explain and , if possible, reconcile the differences between UK and international station availability factors at peak by technology, focusing particularly on CCGTs (PTE Recommendation 19)	5.5	-7.5	6	4
24)-Review approach to 1 in n and how / whether to implement in DDM.	4	-7	7	4
25)-Review how we model demand uncertainty	3	-6	3	0
26)-Investigate (with NG consultants and/or NG operational colleagues) the influence of weather on demand by examining a wider range of weather related factors (humidity, precipitation, air pressure etc.) and whether this could be incorporated into development of Extreme Value Theory (EVT). (PTE Recommendation 18)	3	-6.5	3	-0.5
27)-Consider implementation of enduring recommendation of NG academic consultants on modelling wind demand relationship	3	-9	3	-3

*represents total scores based on scorings provided by National Grid, BEIS and Ofgem. The individual score provided by each organisation was based on the table below.

Table 27: Development Projects Scoring Matrix

Score	Low	Medium	High
Impact	1	2	3
Effort	-1	-2	-3
Priority	1	3	5

A.5 Detailed Modelling Assumptions

The following describes in more detail the modelling assumptions outlined in the main report. National Grid provides the details of the key inputs for the DDM model. All other input assumptions for the DDM are as EMR Scenario 1 from the EMR Delivery Plan.

A.5.1 Demand (annual and peak)

This is the annual and peak demand used for the 4 FES scenarios and Base Case covering the next 15 years. All sensitivities use the same annual and peak demand as their corresponding scenario.

Table 28: Annual Demand* by scenario

Annual Demand TWh	2017	2018	2019	2020	2021	2022	2023	2024
Base Case	328	328	327	325	324	324	325	324
Two Degrees	329	329	328	328	329	330	332	334
Slow Progression	327	326	324	322	320	319	319	320
Steady State	328	328	327	326	325	325	325	324
Consumer Power	328	328	327	326	326	325	325	326

Annual Demand TWh	2025	2026	2027	2028	2029	2030	2031	2032
Base Case	324	323	324	323	324	323	325	325
Two Degrees	338	341	346	349	352	356	359	361
Slow Progression	321	321	323	324	326	327	330	331
Steady State	324	323	324	323	324	323	325	325
Consumer Power	327	328	330	331	333	336	339	342

*The definition of annual demand is GB National Demand plus demand supplied by distributed generation. Annual Demand is in DDM years (Dec to Nov).

Since we carried out our analysis the annual demands for Steady State were revised by a small amount in each year – these revisions do not materially impact our analysis.

Table 29: Peak Demand* by scenario

Peak Demand GW	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Base Case	61.4	61.7	61.6	61.4	61.3	61.4	61.3	61.3
Two Degrees	62.3	62.0	61.9	61.8	61.8	61.9	61.9	62.0
Slow Progression	61.8	61.1	60.7	60.2	60	59.8	59.9	60.0
Steady State	61.2	61.7	61.6	61.3	61.4	61.2	61.3	61.3
Consumer Power	61.5	61.7	61.6	61.5	61.8	61.8	62.0	62.6

Peak Demand GW	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Base Case	61.4	61.4	61.4	61.4	61.3	61.2	61.2
Two Degrees	62.4	62.9	63.4	63.8	64.3	64.7	64.7
Slow Progression	60.0	60.3	60.4	60.7	60.9	61.2	61.6
Steady State	61.4	61.4	61.4	61.4	61.3	61.2	61.2
Consumer Power	63.2	63.6	64.1	64.7	65.2	66.0	66.7

*The definition of peak demand is unrestricted[42] GB National Demand plus demand supplied by distributed generation.

A.5.2 Generation Capacity Mix

The tables below show the generation mix (name plate capacity at winter peak, excluding solar PV) for the 4 FES scenarios and Base Case from the DDM model. Note that the eligible capacity drops from 2017/18 in 2018/19 before increasing in 2019/20 partly due to interconnection which is not eligible to participate in the CM 2018/19 but can participate in other years.

Table 30: Base Case generation capacity mix

Base Case Capacity Mix (GW)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
CM eligible	**66.1**	**58.7**	**61.0**	**59.3**	**57.8**	**57.7**	**59.0**	**59.0**
Non-CM	**25.3**	**31.3**	**29.2**	**29.9**	**30.4**	**32.5**	**31.9**	**32.2**
Total peak capacity	**91.4**	**90.0**	**90.2**	**89.2**	**88.2**	**90.1**	**90.9**	**91.2**

Base Case Capacity Mix (GW)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
CM eligible	**58.8**	**59.2**	**60.3**	**59.9**	**59.4**	**59.3**	**58.9**
Non-CM	**33.1**	**35.0**	**34.7**	**36.0**	**36.4**	**37.0**	**37.1**
Total peak capacity	**91.9**	**94.2**	**95.0**	**95.9**	**95.8**	**96.3**	**96.0**

Table 31: Two Degrees generation capacity mix

Two Degrees Capacity Mix (GW)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
CM eligible	**66.8**	**57.8**	**59.6**	**56.6**	**57.5**	**59.4**	**60.7**	**60.5**
Non-CM	**26.1**	**33.6**	**30.8**	**33.3**	**35.9**	**37.0**	**40.9**	**45.1**
Total peak capacity	**92.9**	**91.3**	**90.4**	**89.9**	**93.4**	**96.4**	**101.6**	**105.5**

Two Degrees Capacity Mix (GW)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
CM eligible	**60.8**	**61.7**	**63.4**	**59.8**	**59.9**	**58.7**	**55.6**
Non-CM	**47.3**	**51.6**	**49.6**	**55.2**	**57.0**	**62.5**	**67.0**
Total peak capacity	**108.1**	**113.3**	**113.0**	**115.0**	**116.9**	**121.2**	**122.6**

[42] i.e. no demand side response or Triad avoidance has been subtracted

Table 32: Slow Progression generation capacity mix

Slow Progression Capacity Mix (GW)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
CM eligible	66.9	59.1	59.7	57.2	54.8	53.9	54.0	54.0
Non-CM	25.3	32.3	30.8	32.1	33.2	34.1	36.9	40.2
Total peak capacity	92.2	91.5	90.5	89.3	88.0	88.1	90.9	94.2

Slow Progression Capacity Mix (GW)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
CM eligible	54.5	55.0	56.8	56.1	55.4	53.0	52.1
Non-CM	43.1	45.9	43.8	46.5	47.9	50.9	53.7
Total peak capacity	97.6	100.9	100.6	102.6	103.3	103.9	105.7

Table 33: Steady State generation capacity mix

Steady State Capacity Mix (GW)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
CM eligible	66.6	59.3	60.3	58.9	60.7	59.9	59.6	59.7
Non-CM	25.2	31.2	28.9	29.4	29.6	31.5	31.9	32.2
Total peak capacity	91.8	90.4	89.2	88.3	90.3	91.4	91.6	91.9

Steady State Capacity Mix (GW)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
CM eligible	60.5	61.2	61.1	62.2	61.5	61.4	61.0
Non-CM	33.1	35.0	34.7	36.0	36.4	37.0	37.1
Total peak capacity	93.6	96.2	95.8	98.2	97.9	98.5	98.1

Table 34: Consumer Power generation capacity mix

Consumer Power Capacity Mix (GW)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
CM eligible	66.6	59.2	62.0	57.9	59.9	60.1	61.4	65.2
Non-CM	25.4	32.7	29.8	31.2	32.7	33.4	35.7	37.2
Total peak capacity	91.9	91.8	91.9	89.1	92.5	93.5	97.2	102.4

Consumer Power Capacity Mix (GW)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
CM eligible	65.0	66.5	68.0	68.2	66.2	65.0	66.4
Non-CM	39.8	43.0	41.8	43.3	46.7	49.3	52.1
Total peak capacity	104.8	109.6	109.8	111.4	112.8	114.4	118.5

A.5.3 CM-ineligible Capacity

The following tables give a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2021/22 and 2018/19. The total capacity is lower than the nameplate capacity shown in A5.2 since it is de-rated.

Note that the ineligible capacity is less in 2021/22 than 2018/19 as interconnection is included in the ineligible capacity in 2018/19.

Table 35: Breakdown of De-rated CM ineligible capacity for 2021/22

Generation type	Capacity (in GW)
Onshore Wind	3.0
Offshore Wind	1.9
Biomass	2.8
Autogeneration	1.2
Hydro	0.9
Landfill	0.6
Other	1.3
Total	11.6

Table 36: Breakdown of De-rated CM ineligible capacity for 2018/19

Generation type	Capacity (in GW)
Onshore Wind	2.9
Offshore Wind	1.4
Biomass	2.8
Autogeneration	1.2
Interconnection	2.1
Hydro	0.8
Landfill	0.6
Other	1.0
Total	12.8

A.5.4 Station Availabilities

These are the station availabilities used for the 4 FES scenarios, Base Case and the High and Low availability sensitivities (rounded to the nearest %). Note the two sensitivities cover the two most uncertain technologies of CCGT and Nuclear.

In last year's ECR, all small scale / embedded technologies were mapped to the closest equivalent transmission connected technology class. This year for the 2017 ECR, small scale/embedded CM-eligible technologies are again kept consistent with this basis as required by the CM rules. However, for some small scale non-CM technologies (which are modelling assumptions as opposed to a CM rules requirement), we have amended the de-rating factors based on the best range of data sources available to us at this time. Further development work and engagement with industry/government/regulator stakeholders will continue next year to improve the modelling of such small scale embedded technologies that are connected at distribution level and for which we have no direct visibility.

Table 37: Station availabilities by sensitivity

	Base	High Availability	Low Availability
CCGT 2018/19	**89%**	**92%**	**85%**
CCGT 2019/20	**89%**	**92%**	**86%**
CCGT 2020/21 onwards	**90%**	**93%**	**87%**
Coal	88%	88%	88%
Nuclear (Existing)	**85%**	**89%**	**82%**
Nuclear (New)	**90%**	**90%**	**90%**
ACT Advanced	88%	88%	88%
ACT CHP 2018/19	88%	88%	88%
ACT Standard	88%	88%	88%
AD 2018/19	64%	64%	64%
AD 2019/20	66%	66%	66%
AD 2020/21	68%	68%	68%
AD 2021/22 onwards	70%	70%	70%
AD CHP 2018/19	64%	64%	64%
AD CHP 2019/20	66%	66%	66%
AD CHP 2020/21	68%	68%	68%
AD CHP 2021/22 onwards	70%	70%	70%
Autogeneration	90%	90%	90%
Biomass CHP	88%	88%	88%
Biomass Conversion	88%	88%	88%
Coal CCS	88%	88%	88%
CHP (large scale)	**As CCGT**	**As CCGT**	**As CCGT**
Dedicated Biomass	88%	88%	88%
EfW	88%	88%	88%
EfW CHP	74%	74%	74%
Gas CCS	**As CCGT**	**As CCGT**	**As CCGT**
Gas Turbine	95%	95%	95%
Geothermal	88%	88%	88%
Geothermal CHP	88%	88%	88%
Hydro	88%	88%	88%
Landfill	59%	59%	59%
OCGT	95%	95%	95%
Oil	88%	88%	88%
Pumped storage	96%	96%	96%
Sewage Gas	49%	49%	49%
Solar PV	0%	0%	0%
Tidal	22%	22%	22%
Wave	22%	22%	22%

Note that the High and Low Availability only adjust CCGTs and nuclear as shown above in bold.

A.5.5 Reserve to cover largest infeed loss

National Grid has to hold capacity in reserve in order to maintain system operability if a loss of generating capacity occurs. This capacity has to be accounted for in the LOLE calculation and is added to the peak demand assumptions. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held.

Table 38: Reserve to cover largest infeed loss by scenario

In Feed Loss GW	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Base Case	0.9	0.9	0.9	1.0	1.0	1.7	1.9	1.9
Two Degrees	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Slow Progression	0.8	0.9	0.9	1.0	1.0	1.1	1.1	1.1
Steady State	0.8	0.9	0.9	0.9	1.9	1.9	1.9	1.9
Consumer Power	0.8	0.9	0.9	0.9	1.0	1.1	1.1	2.0

In Feed Loss GW	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Base Case	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Two Degrees	1.0	1.6	1.6	1.6	1.6	1.6	1.6
Slow Progression	2.0	2.0	2.0	2.0	2.1	1.2	1.8
Steady State	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Consumer Power	2.0	2.0	2.0	2.0	2.0	2.0	1.8

Note: the largest infeed loss above is not included in the peak demand values shown earlier.

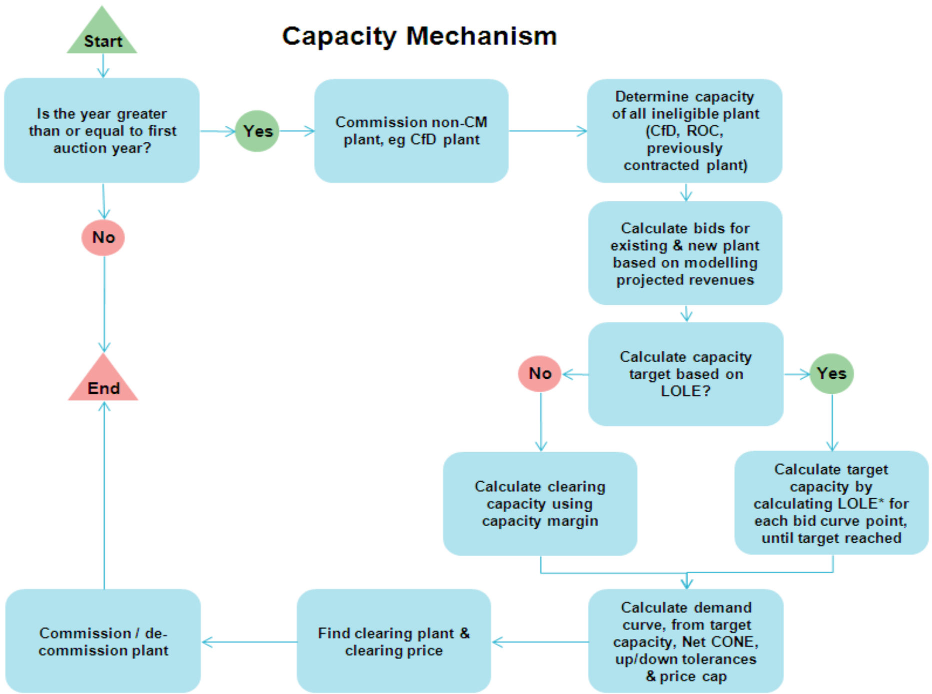
A.6 Detailed Modelling Approach

The following describes in more detail the modelling approach used in this report and expands on Section 2.1.

A.6.1 Using DDM to model capacity to secure

The DDM is able to model investment decisions for renewable and low carbon technology, so it was used by BEIS (formerly DECC) and National Grid for the analysis to calculate the CfD strike prices for the EMR Delivery Plan. The DDM also has the functionality to model the Capacity Market and so it has been used in this analysis to determine the capacity to secure. The following diagram illustrates the process at a high level:

Figure 28: Capacity Market flow chart[43]



2021/22 Modelling Steps

The key steps in the modelling of the capacity to secure from 2021/22 are outlined below:

1. The model settings determine when the first auction is run. For the 2021/22 analysis, the first auction simulated is in 2017/18 for delivery in 2021/22. The model assumes that an auction is run in all subsequent years from 2017/18.

2. The generation capacity described in sections 3.6 and 3.7 (plus demand side response in 3.8) can be split into capacity that is eligible for the Capacity Market and capacity that is not eligible for the Capacity Market. All of the non-eligible FES capacity determined by the underlying scenario is included in the modelling. The probabilistically modelled contribution of interconnection is included in the eligible capacity.

3. All of the non-eligible capacity has its de-rated capacity calculated (based on updated capacity and de-rating factor values), which may include plants that have a Capacity Market agreement longer than a year if they are assumed to be operational in the scenario or sensitivity being modelled. This non-eligible capacity will be accounted for before any Capacity Market auction is run. Note that the calculated de-rated capacity for a contracted plant may be different to the contracted capacity awarded in the auction.

4. All existing and potential new capacity is ranked by their bids into the auction based on modelled revenues and expenditure. Interconnection is assumed to bid in at zero since the DDM does not model the economics of generation in interconnected countries.

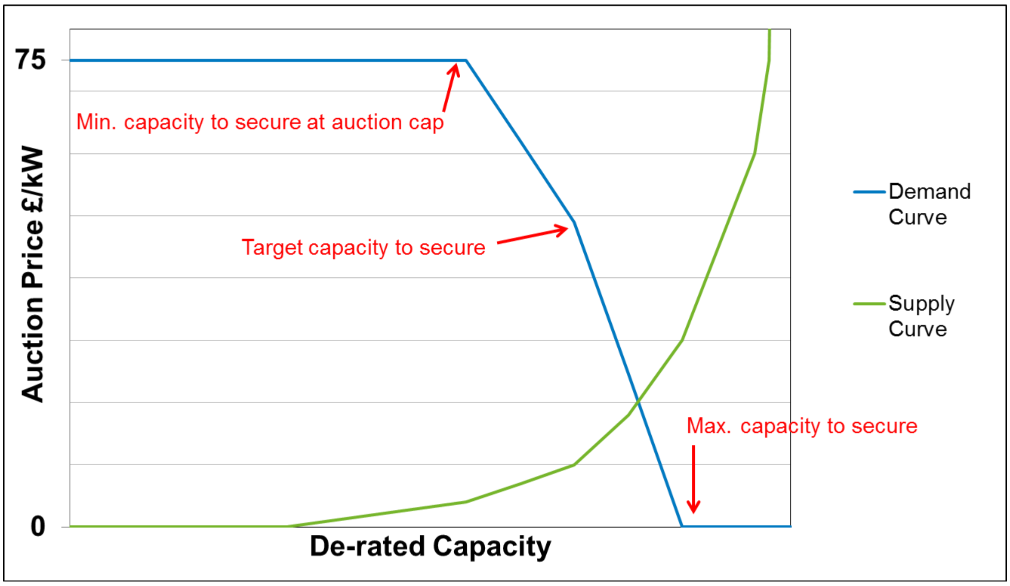
[43] Chart supplied by Lane, Clark and Peacock LLP (LCP) http://www.lcp.uk.com/

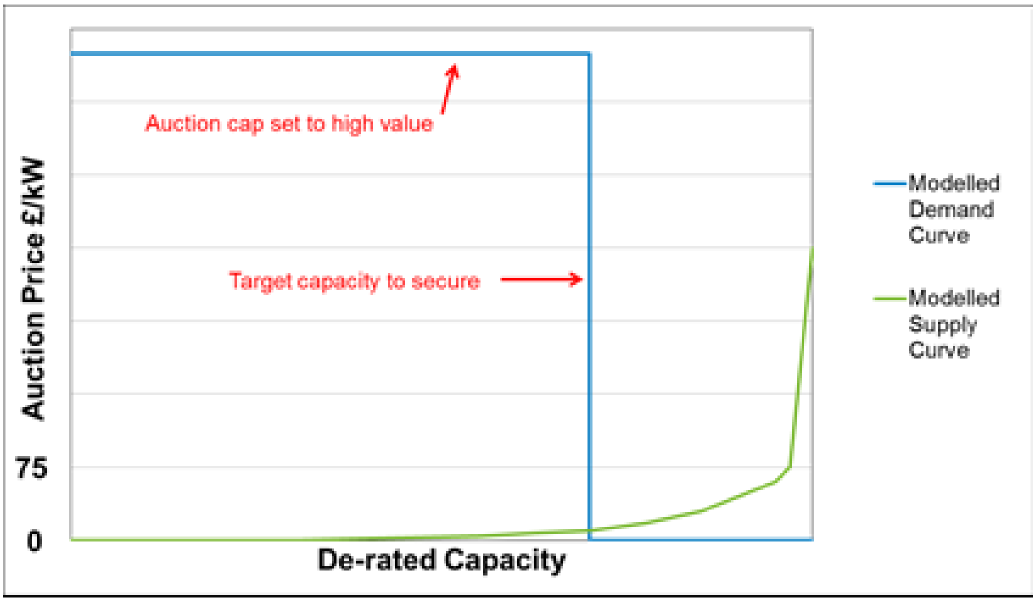
5. The model has the option to target either an LOLE or a capacity margin. For this analysis a target LOLE of 3 hours is used.

6. The model then assesses the LOLE associated with each increasing bid in the Capacity Market auction. The capacity not eligible for the Capacity Market auction is accounted for first. The model calculates LOLE by probabilistically modelling conventional generation using its availability e.g. if a plant has 90% availability then there is 90% chance that plant will be available to generate at its full capacity. For interconnection, the expected contribution is determined by probabilistic modelling using a set of flow distributions obtained from National Grid's pan European model. For wind capacity the generation is sampled using historical onshore and offshore wind streams. There is loss of load if demand exceeds available generation. The demand is determined by the input peak demand and this is used to scale a historic demand curve.

7. In most cases (outside of the ECR) the model uses an auction demand curve (illustrated in Figure 29a), which allows the model to determine a level of capacity accounting for the cost of capacity which enters the auction. For this analysis, the capacity to secure is that which ensures exactly 3 hours LOLE. To achieve this, the demand curve in the model has been altered (illustrated in Figure 29b) by raising the cap well above the usual value (£75 /kW) which allows the model to contract the capacity required:

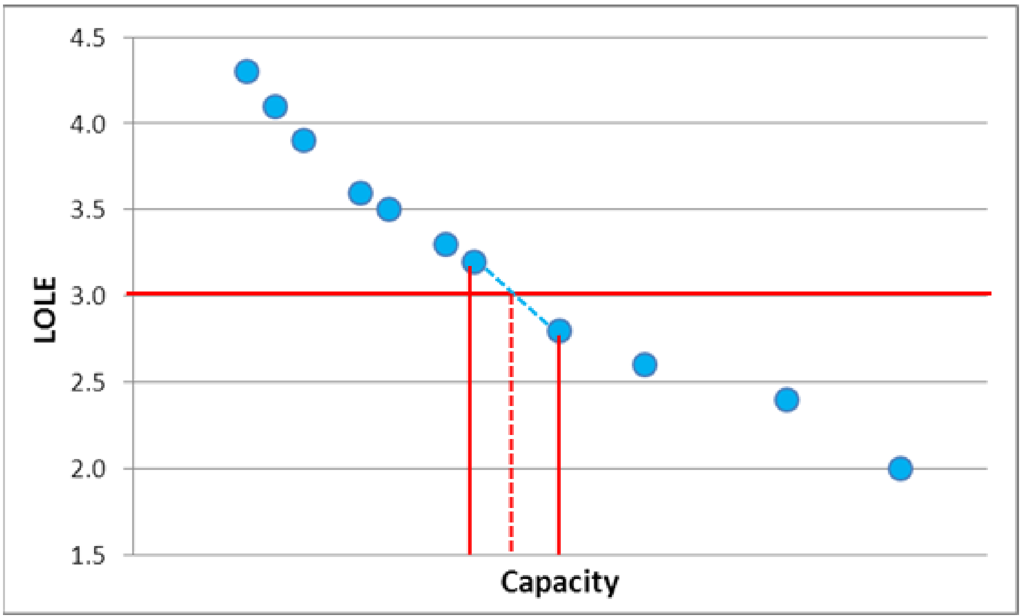
Figure 29: a) Realistic and b) Modelled Demand Curves (Illustrative)





8. Given the model has to ensure 3 hours LOLE by using a combination of new and existing plants and demand side response and these plants have specific capacities it is unlikely that the LOLE will be exactly 3 hours. In order to compensate for this the model also interpolates between the two marginal plants around 3 hours LOLE to determine the exact capacity to hit 3 hours LOLE as illustrated below:

Figure 30: Model interpolation to achieve 3 hours LOLE



9. This de-rated capacity is reported for each year modelled from 2021/22 to 2031/32 and is split as follows:

- Total de-rated capacity required to hit 3 hours LOLE
- De-rated capacity to secure in the Capacity Market auction
- De-rated capacity expected to be delivered outside the Capacity Market auction
- Total nameplate capacity split by CM and non-CM eligible technologies.

2018/19 Modelling

For the 2018/19 analysis the modelling follows a similar process to the 2021/22 analysis described in the preceding pages. The key differences in the modelling steps for 2018/19 are highlighted below.

1. The first auction simulated is the T-1 auction for delivery in 2018/19.

3. The non-eligible capacity includes plants that have a Capacity Market agreement for 2018/19 (including one year contracts as well as longer contracts if they are assumed to be operational in the scenario or sensitivity being modelled).

4. For interconnection in 2018/19, we have assumed a static peak flow that is based on the de-rating factors used in the 2017/18 Early Auction and 2019/20 T-4 auction and a range of static flow sensitivities.

9. Although the model simulates auctions in later years only the results for 2018/19, 2019/20 and 2020/21 from this analysis have been used in this report.

A.6.2 Treatment of Generation Technologies

The DDM models a range of generation technology types. For this analysis they are broadly the same categories that were modelled in the EMR Delivery Plan. As outlined in Table 39, for most of these technologies, the entire fleet is either assumed to be all eligible for the Capacity Market or all not eligible. The exceptions are hydro and autogeneration capacity, for which the fleet is split between both categories.

For any technology receiving support, plants are eligible to participate in the Capacity Market when this support has finished. Any unsupported generation capacity that is under a total capacity of 2 MW is not eligible for the Capacity Market unless it is combined with other capacity by an aggregator to give a total above 2 MW. The unsupported generation capacity that is under 2 MW has been estimated by National Grid to range from 1.1 GW to 1.6 GW in the period to 2021/22 depending on the FES scenario and year (including some onsite autogeneration above 2MW assumed to opt out of the Capacity Market).

The following table lists generation technologies modelled and whether they are assumed to be Capacity Market eligible or not (before support finishes).

Table 39: Capacity market classification of generation capacities

Type	Capacity Market Eligible	Outside of Capacity Market
CCGT	✓	
Coal	✓	
Nuclear (Existing)	✓	
Nuclear (New)		✓
Onshore Wind		✓
Offshore Wind		✓
ACT Advanced		✓
ACT CHP		✓
ACT Standard		✓
AD		✓
AD CHP		✓
Biomass CHP		✓
Biomass Conversion		✓
Coal CCS		✓
CHP/Autogeneration	✓	✓
Dedicated Biomass[44]		✓
Domestic battery storage		✓
EfW	✓	
EfW CHP		✓
Gas CCS		✓
Gas Turbine	✓	
Geothermal		✓
Geothermal CHP		✓
Hydro	✓	✓
Landfill		✓
OCGT	✓	
Oil	✓	
Transmission / Distributed Storage technologies (e.g. battery and pumped storage)	✓	
Sewage Gas		✓
Solar PV		✓
Tidal		✓
Wave		✓

[44] Note for existing biomass which receives support under the RO its capacity will be outside of the Capacity Market

A.7 Least Worst Regret

A.7.1 Approach

The analysis used to recommend the capacity to secure utilises a Least Worst Regret (LWR) approach. When deciding on an option, LWR aims to minimise the cost implications of any decision made when there is uncertainty over the future. One benefit of this approach is that it is independent of the probabilities of the various potential future outcomes and therefore it can be used when the probabilities of these outcomes are unknown, providing that the cases considered cover a range of credible outcomes. This approach has been endorsed by BEIS's PTE and was supported at the National Grid Implementation Co-ordination Workshop on 13th March 2014, as being the most appropriate way of choosing the recommended de-rated capacity to secure at auction. It accounts for the cost of securing capacity and the cost of loss of load events (i.e. cost of unserved energy). There was general agreement that the unit costs used in the approach should be supplied by BEIS based on public domain information.

The approach involves considering each potential de-rated capacity choice (i.e. the required level to ensure it meets 3 hours LOLE) derived from a particular outcome (scenario or sensitivity) and assessing the cost of the other potential outcomes under that capacity choice to find the maximum regret cost for that potential choice. In other words, if a particular de-rated capacity level is chosen then this approach assesses the worst outcome (arising from under or over securing) that can be expected if a different scenario or sensitivity occurs in future. To do this, a base cost for that case is calculated as the cost associated with the required level of de-rated capacity. For the other outcome cases assessed against that de-rated capacity choice, the regret cost is defined as the absolute value of the difference between the total cost and the base cost. The maximum regret cost for a potential de-rated capacity level is then calculated as the highest of the regret costs across all cases, i.e. the highest cost difference arising from over or under securing.

This process is repeated for each potential de-rated capacity choice to find the minimum of the maximum regret costs over all potential choices derived from all scenarios and sensitivities. The Least Worst Regret option is the potential de-rated capacity level with the minimum of the maximum regret costs. This is the same principle used in National Grid's Network Options Assessment (NOA)[45] to choose between potential transmission network reinforcement options. This approach was also used to assess the volume required for National Grid's Contingency Balancing Reserve[46] in 2014/15, 2015/16 and 2016/17.

In order to determine the maximum regret cost for a particular case, a view on the unit de-rated capacity cost and unit cost of unserved energy is required. Costs obtained directly from the modelling have not been used; furthermore, the auction process itself will determine the outturn costs.

As per previous ECR analysis, the following costs consistent with the Reliability Standard are used; VoLL (Value of Lost Load) = £17,000/MWh as the unit cost of Expected Energy Unserved (EEU) and £49/kW/year[47] as the unit cost of de-rated capacity.

[45] See http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Network-Options-Assessment/

[46] See http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/

[47] Net CONE (Cost of New Entry) as outlined in the EMR Stakeholder bulletin issued on May 14th 2014

The total cost of a case (scenario or sensitivity) is calculated as:

Total Cost = Cost of De-Rated Capacity to Secure + Cost of EEU

where:

Cost of De-Rated Capacity to Secure = De-Rated Capacity Secured (MW) * Unit cost of De-Rated Capacity (£/MW)

and:

Cost of EEU = EEU (MWh) * Unit Cost of Unserved Energy (£/MWh)

In this year's ECR all sensitivities are applied to the Base Case. Note that the cost of capacity secured in previous auctions and any penalty payments for non-delivery are excluded from the above calculation. In October, following prequalification, our Adjustment to Demand Curve Report to the Secretary of State will take account of any known non-delivery issues such as contracted plant closures or terminated capacity market agreements.

The charts in section A.7.4 illustrate how the total cost varies across the cases modelled for different potential levels of capacity secured in 2018/19 and 2021/22.

A worked example of LWR, taken from the analysis for the 2017/18 Early Auction can be found in the 2016 Electricity Capacity Report[48].

A.7.2 Academic Consultants' Review of Alternatives to LWR

As outlined in Section 2.5.2, in their 2016 report, BEIS' Panel of Technical Exports (PTE) made a recommendation (no. 25) that National Grid should review its overall modelling strategy and consider a range of options for assigning weights or probabilities. As a result, we commissioned our academic consultants from Heriot Watt and Edinburgh Universities (Zachary, Wilson with support from Dent) to review the current approach and to look at options to incorporate probabilities of sensitivities into the process for determining the recommended capacity in the ECR. Although this review did not lead to a change of approach in this year's ECR, it proved to be a valuable and informative piece of research. For this reason, a summary of some of the key points from the consultants' report and follow on analysis have been included in the Annex in the sections below.

Sensitivity Probabilities

As part of the review of approaches we asked the consultants to consider whether any objective approach could be adopted to calculate probabilities for sensitivities including non-delivery sensitivities as part of looking at the PTE's recommendation (no. 17) in their 2016 report.

The consultants concluded that sensitivities defined by, for example, extremes of weather conditions might, with sufficient data, be probabilistically quantified. However, sensitivities corresponding to, for example, significant non-delivery of contracted conventional generation are very difficult to objectively quantify in any probabilistic sense, as the relevant data simply does not exist. For sensitivities like these, the estimation of such probabilities would have to be a matter of expert judgement.

[48] P105-107 in https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf

Exponential Approximation

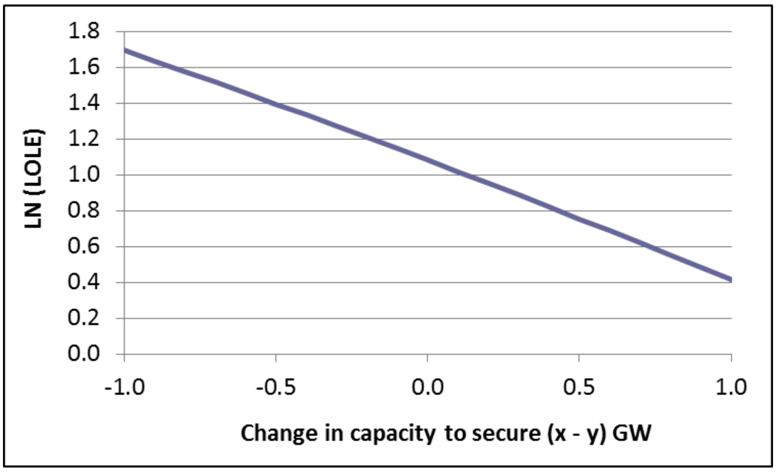
In carrying out their review, the consultants observed that for each scenario / sensitivity modelled LOLE decays / grows exponentially as capacity to secure increases / decreases away from the value that meets the Reliability Standard so that LOLE (hours) can be approximated by an exponential function with parameter λ:

$$\text{LOLE}(x) = 3 * e^{-\lambda (x-y)}$$

where x is the capacity to secure (in GW) and y is the capacity value (in GW) that meets the 3 hours Reliability standard for that scenario / sensitivity. This means that $\log_e$ LOLE is approximately linearly related to the change in capacity to secure. The exponential decay parameter λ of the exponential function can be estimated from the slope of $\log_e$ LOLE against change in capacity to secure from the value for that scenario / sensitivity that meets the 3 hours LOLE Reliability Standard.

Figure 31 (based on outputs from National Grid analysis) illustrates the linear relationship between $\log_e$ LOLE and change in capacity to secure which validates the exponential approximation used.

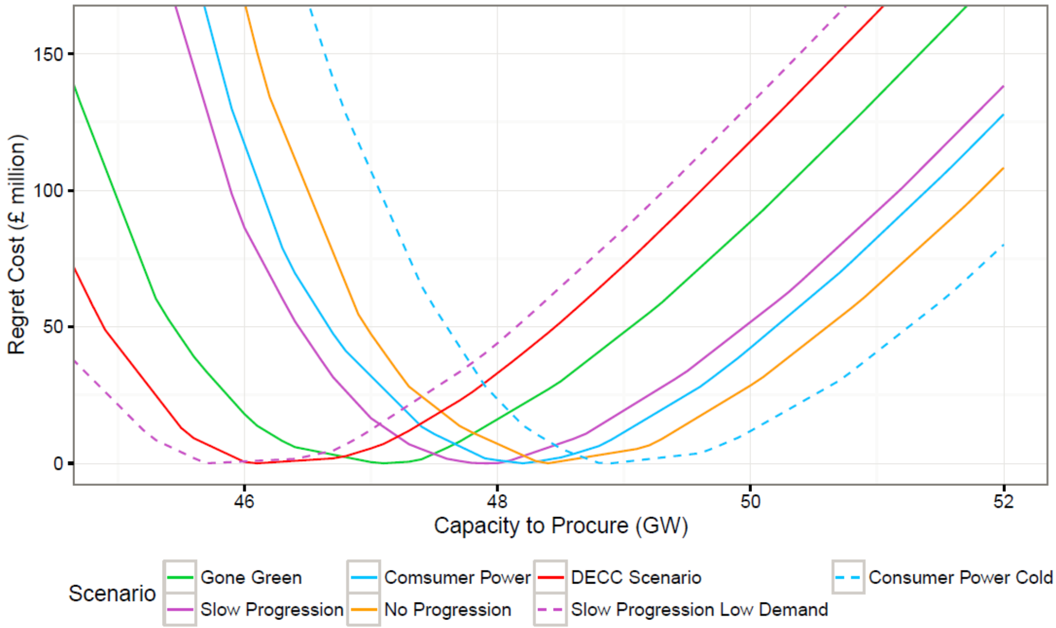
Figure 31 : Illustration of $\log_e$ LOLE against change in capacity to secure



Current LWR approach

Zachary and Wilson pointed out that LWR essentially determines a compromise between the capacities to secure defined by the most optimistic and pessimistic of the sensitivities modelled. The specification of the boundaries of the set of scenarios and sensitivities to be considered in itself introduces subjectivity into such an analysis. The solution of a LWR analysis is given by the value corresponding to the point of intersection of the regret cost functions for the two extreme sensitivities as illustrated in Figure 32 using data from the analysis for 2019/20 in the 2015 ECR.

Figure 32 Regret cost functions for five scenarios and the two most extreme sensitivities in the 2015 ECR



Source: Zachary and Wilson (2017)

In this illustration, the intersection of the two functions gives 47.8 GW: the sensitivity with requirement closest to this value was the Consumer Power High Availability at 47.9GW, which was the recommended capacity to secure in the 2015 ECR.

Given these features of LWR, consultants considered alternative approaches to LWR as described below.

Weighted LWR approach

In this approach, weights (less than 1) are applied to one or more sensitivities in the LWR tool which has the effect of applying a scaling to the regret cost function. The consultants concluded that applying weightings (less than 1) to sensitivities in the LWR analysis does not in general work satisfactorily. In most cases applying weightings does not affect the LWR result. If low weights are applied to the lowest and highest sensitivities, they can lose their influence on the LWR result, but this only has the effect of selecting different sensitivities to become the most optimistic and pessimistic sensitivities that determine the LWR outcome.

A fully probabilistic analysis

An alternative fully probabilistic approach would require probabilities to be assigned to all the individual scenarios and sensitivities. The capacity to secure would then be determined, for example, on the basis of the overall (unconditional) distribution of the supply demand balance, or equivalently on the basis of the unconditional LOLE expressed as a function of the capacity to secure. The consultants concluded that a fully probabilistic analysis would seem to be preferable to LWR since less likely scenarios and sensitivities may be assigned suitably small probabilities so that they do not unduly influence the outcome. However, they also concluded that the assignment of probabilities is necessarily subjective, leading to an often expressed preference for the use of LWR which (because of the influence of the boundaries of the set of scenarios and sensitivities) may not be any less subjective.

Hybrid Approach

Zachary and Wilson's report observes that (due to the subjectivity / difficulty involved), there is reluctance in assigning probabilities to the scenarios and main sensitivities while at the same time there is also a desire to take account of the probabilities (which may be small) of additional sensitivities that are extreme in terms of their capacity requirements without these extreme cases exerting undue influence. It recommends considering a “hybrid approach” which attempts to reconcile as far as possible these conflicting requirements. This hybrid approach can be implemented using the following steps.

1. The first step is to agree the set of scenarios and sensitivities of interest and to split this into a core set ($\mathcal{C}$), each of which is considered to be plausible (as per the current ECR approach), together with a further set of extreme sensitivities (including potential combinations of independent sensitivities in the core set).

2. The report shows that the core set can be represented as a single scenario with a capacity to secure ($\bar{x}_{\mathcal{C}}$) determined by LWR as per current approach (or an alternative methodology if preferred) and an estimated core set LOLE exponential decay parameter ($\lambda_{\mathcal{C}}$). This step estimates the values of these parameters.

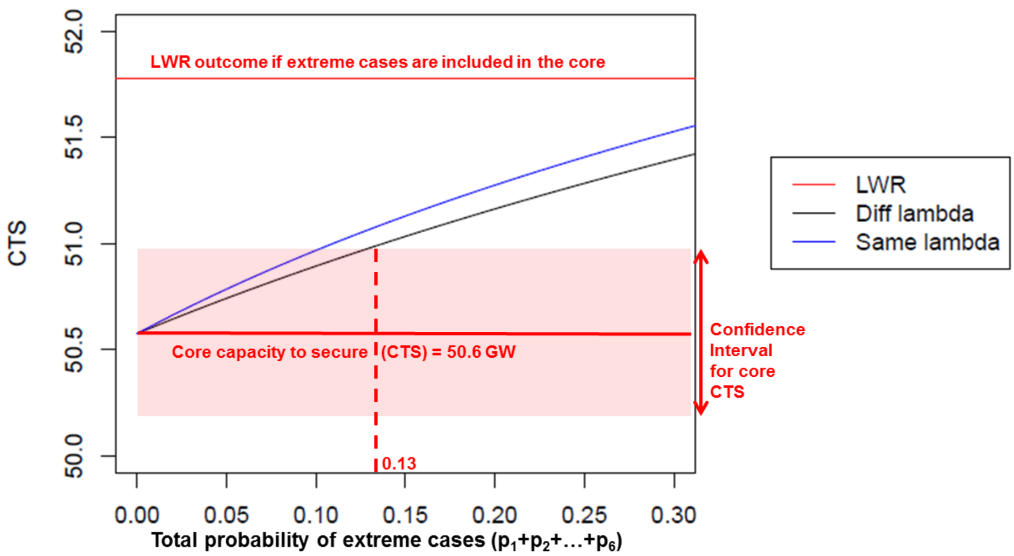
3. For cases outside of the core set, the next step is to assign probabilities (p_i) to the extreme set ($\mathcal{E}$) which would be a matter of expert judgementt, particularly for non-delivery sensitivities.

4. The report states that each of the extreme cases can be represented using the exponential approximation described earlier. This step calculates the exponential decay parameters (λ_i) and capacity requirements ($\bar{x}_i$) to meet the Reliability Standard for the extreme cases.

5. The report shows that the impact of the sensitivities in the extreme set can be determined probabilistically resulting in a correction to the capacity to secure of the core set. The report derives a formula to calculate the capacity to secure ($\bar{x}_{\mathcal{S}}$) for the whole set of cases modelled. The correction ($\bar{x}_{\mathcal{S}}-\bar{x}_{\mathcal{C}}$) can be identified in the solution to this formula:
$$\left(1-\sum_{i\in\mathcal{E}} p_i\right)e^{-\lambda_{\mathcal{C}}(\bar{x}_{\mathcal{S}}-\bar{x}_{\mathcal{C}})}+\sum_{i\in\mathcal{E}} p_i e^{-\lambda_i(\bar{x}_{\mathcal{S}}-\bar{x}_i)}=1.$$
Source: Zachary and Wilson

The report contained an illustrative example showing how the hybrid approach could be applied with an extreme set of six cases assumed to have equal probabilities. The following chart adapted from report shows how the capacity to secure (CTS) for the whole set changes with total extreme sensitivity probability in the illustrative example where the decay parameters (λ_i) for all the extreme cases are different to (black line) and the same (blue line) as the decay parameter ($\lambda_{\mathcal{C}}$) for the core set. Figure 33 also shows what the LWR outcome would have been if the extreme cases had been include in the core set (top red line).

Figure 33 : Illustration of impact of extreme set probabilities



Source: Zachary and Wilson (with 95% confidence interval and text added by National Grid)

Figure 33 shows that in the hybrid approach, the influence of the extreme cases on the CTS is much less than if these cases had been included in the core set. In addition the combined probability of the extreme cases in this example would need to be at least 0.13 for the CTS value to lie outside of the 95% confidence interval for the core CTS (as described in the 2016 ECR[49]).

A.7.3 National Grid's indicative hybrid approach analysis for 2020/21

Following positive feedback from BEIS, Ofgem and the PTE on Zachary and Wilsons' report on the proposed hybrid approach, we carried out indicative analysis using the hybrid approach to see if is likely to result in a material difference to the capacity to secure (CTS) i.e. moving it outside the confidence interval of the core set LWR outcome.

This indicative analysis approach utilised a core set based on the 22 scenarios and sensitivities for 2020/21 described in Chapter 5 of the 2016 ECR for 2020/21 and an extreme set of four combined sensitivities.

Core Scenarios / Sensitivities:

- Four 2016 FES (GG, NP, CP, SP) and a Base Case (BC)
- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Weather Cold Winter 2010/11 (COLD)
- Weather Warm Winter 2006/07 (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand peak compared to forecast peak (HIGH DEMAND)
- Low Demand peak compared to forecast peak (LOW DEMAND)
- Coal Non Delivery (NON DEL): 9 sensitivities in 400 MW increments up to 3600 MW

[49] P31-32 in https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf

Extreme Sensitivities:

For the indicative analysis, we used four extreme sensitivities based on combinations of core sensitivities (from the 2016 ECR) and / or combinations of non-delivery and over-delivery for 2020/21.

1. Warm winter (2006/07) and 2 GW over-delivery (WARM_OVER_DEL_2000):
   - Additional interconnector imports (1 GW) - due to early delivery of new interconnectors or imports above de-rated values.
   - Conventional capacity (1 GW) – due to 2 uncontracted units staying open
2. Warm winter (2006/07) and low peak demand (WARM_LOW_DEMAND)
3. Cold winter (2010/11) and 3.6 GW non-delivery (COLD_NON_DEL_3600)
4. Combined Non-Delivery of 5.8 GW (NON_DEL_5600) comprised of:
   - Small scale capacity (2 GW) - due to policy / code changes
   - Coal (1.8 GW) - 1 plant closing e.g. breakdowns, outages etc.
   - Interconnection (1 GW) - due to late delivery of new ICs or breakdowns

Capacity to secure range

Table 40 shows the estimated capacity required to meet the Reliability standard values for core and extreme cases (based on 2016 ECR analysis). The table is sorted in order of the capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM and the difference from the core set LWR outcome of 49.5 GW.

Table 40: De-rated capacities indicative analysis (based on 2016 ECR) - 2020/21

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Difference from Core CtS
Base Case Warm Winter Over Delivery Sens.: 2000	BC_WARM_OVER_DEL_2000	44.1	17.4	-5.4
Base Case Warm Winter Low Demand	BC_WARM_LOW_DEMAND	45.0	15.4	-4.5
Base Case Warm Winter	BC_WARM	46.1	15.4	-3.4
Base Case Low Demand	BC_LOW_DEMAND	46.7	15.5	-2.8
Slow Progression	SP	47.0	15.2	-2.5
No Progression	NP	47.1	16.1	-2.4
Base Case High Wind	BC_HIGH_WIND	47.5	15.8	-2.0
Base Case	BC	47.7	15.5	-1.8
Base Case Low Availability	BC_LOW_AVAIL	47.7	15.6	-1.8
Base Case High Availability	BC_HIGH_AVAIL	47.7	15.5	-1.8
Base Case Low Wind	BC_LOW_WIND	47.8	15.3	-1.7
Base Case Non Delivery Scenario: -400	BC_NON_DEL_400	48.1	15.1	-1.4
Gone Green	GG	48.1	14.2	-1.4
Base Case Non Delivery Scenario: -800	BC_NON_DEL_800	48.5	14.7	-1.0
Base Case Cold Winter	BC_COLD	48.6	15.6	-0.9
Base Case High Demand	BC_HIGH_DEMAND	48.8	15.6	-0.7
Base Case Non Delivery Scenario: -1200	BC_NON_DEL_1200	48.9	14.3	-0.6
Base Case Non Delivery Scenario: -1600	BC_NON_DEL_1600	49.3	13.9	-0.2
Consumer Power	CP	49.5	14.0	0.0
Base Case Non Delivery Scenario: -2000	BC_NON_DEL_2000	49.7	13.5	0.2
Base Case Non Delivery Scenario: -2400	BC_NON_DEL_2400	50.1	13.1	0.6
Base Case Non Delivery Scenario: -2800	BC_NON_DEL_2800	50.5	12.7	1.0
Base Case Non Delivery Scenario: -3200	BC_NON_DEL_3200	50.9	12.3	1.4
Base Case Non Delivery Scenario: -3600	BC_NON_DEL_3600	51.3	11.9	1.8
Base Case Cold Winter Non Delivery Sens.: -3600	BC_COLD_NON_DEL_3600	52.2	12.0	2.7
Base Case Non Delivery Scenario: -5800	BC_NON_DEL_5800	53.5	9.7	4.0

Scenario Colour Key
Gone Green
Slow Progression
No Progression
Consumer Power
Base Case

Total derated capacity (GW) =
Capacity to Secure (GW)
+ Outside Capacity Market (GW)

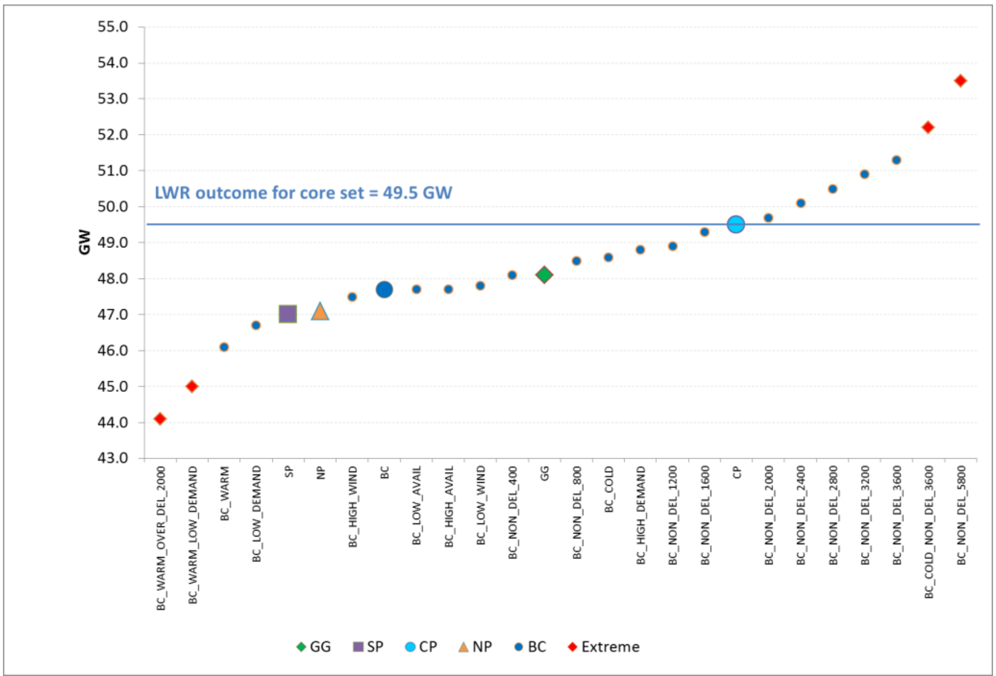
Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity and over-delivery sensitivities by increasing "Outside CM" capacity.

The warm winter over delivery sensitivity and the 5600 MW combined non-delivery sensitivity define the extremes of the capacity to secure range for 2020/21 indicative hybrid analysis (44.1 GW to 53.5 GW).

Capacity to secure chart

Figure 34 illustrates the full range of potential capacity levels and identifies the LWR outcome from the core set for 2020/21

Figure 34: LWR outcome for core set compared to individual cases – 2020/21



Hybrid Approach Parameters

For this analysis, we used an estimate of 0.7 for the decay parameter (λc) for the core scenarios / sensitivities as used in the illustrative analysis carried out by our Zachary and Wilson who used a similar core set of scenarios and sensitivities based on the 2016 ECR analysis.

Zachary and Wilson also calculated decay parameters (λ_i) for one extreme optimistic case (WARM_LOW_DEMAND) and one extreme pessimistic case (COLD_NON_DEL_3600) included in the indicative analysis. The decay parameters for the other extreme optimistic and pessimistic cases were assumed to be the same as the above cases. The set of decay parameters used is shown in the table below:

Table 41: Indicative Hybrid Approach Parameters - 2020/21

Scenarios / Sensitivities	Decay Parameter	CTS (GW)
CORE SET	0.70	49.5
1. WARM_OVER_DEL_2000	0.93	44.1
2. WARM_LOW_DEMAND	0.93	45.0
3. COLD_NON_DEL_3600	0.63	52.2
4. NON_DEL_5800	0.63	53.5

Probabilities for cold and warm weather

Based on values set out in Chapter 8 of the 2015 ECR (from a 30 year weather history), a winter at least as cold as 2010/11 is expected 1 in 5 years (probability 0.2) and a winter at least as warm as 2006/07 is expected 1 in 15 years (probability 0.067). Note that since this indicative analysis was carried out, these numbers have been revised (see sections 3.10.6 and 3.10.7 of the 2017 ECR for the latest values).

Probabilities for high and low demand

The high and low demand sensitivities are based on the EMR Demand Forecasting Incentive for the T-1 auction - this has a symmetric range of +/- 2% around the forecast peak demand. In previous analysis discussed presented in Chapter 8 of the 2015 ECR, the within year historical transmission peak demand forecast error had a standard deviation of ~2%.

Assuming that in future years the within year peak forecast error is normally distributed with a standard deviation of 2% and mean of 0%, the probability of outturn peak demand being one standard deviation (2%) below or lower than the within year forecast is around 0.159.

Similarly the probability of outturn peak demand being 2% above (or higher) than the within year forecast is also assumed to be around 0.159.

Probabilities for extreme cases

Cold winter (2010/11) and 3.6 GW non-delivery (COLD_NON_DEL_3600)
If we assume that the 3.6 GW non-delivery case has a probability of ~0.045 (the average for the core set) and that cold winter and non-delivery are independent, then the probability of the COLD_NON_DEL_3600 sensitivity is estimated to be ~ 0.2 * 0.045 = 0.009.

Combined Non-Delivery of 5.8 GW (NON_DEL_5600)
We had no means of estimating the probability of this sensitivity so we assumed the probability of this sensitivity was the same as other pessimistic extreme case (COLD_NON_DEL_3600) i.e. 0.009

Warm winter (2006/07) and low peak demand (WARM_LOW_DEMAND)
Assuming that warm winter and low demand are independent events, using the above probabilities, this sensitivity is estimated to have a probability of ~ 0.067 * 0.159 = 0.011

Warm winter (2006/07) and 2 GW over-delivery (WARM_OVER_DEL_2000):
We had no means of estimating the probability of this sensitivity so we assumed the probability of this sensitivity was the same as other optimistic extreme case (WARM_LOW_DEMAND) i.e. 0.011.

Hybrid Analysis Correction

Using the formula outlined previously, the correction to the capacity to secure of the core set ($\bar{x}_S - \bar{x}_C$) is **0.21 GW**. This value is within the confidence interval of the core capacity to secure calculation and hence in this indicative analysis, applying the hybrid approach would not result in a material change.

We also calculated what the correction would be for a range of different extreme case probability values to see what the values would need to be to result in a material change to the capacity to secure (See Table 42).

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Table 42: Impact of probabilities on indicative analysis - 2020/21

Sensitivities / CTS	Combinations of probabilities for cases							
CORE SET	0.960	0.980	0.960	0.940	0.920	0.900	0.880	0.860
1. WARM_OVER_DEL_2000	0.011	0.005	0.010	0.015	0.02	0.025	0.030	0.035
2. WARM_LOW_DEMAND	0.011	0.005	0.010	0.015	0.02	0.025	0.030	0.035
3. COLD_NON_DEL_3600	0.009	0.005	0.010	0.015	0.02	0.025	0.030	0.035
4. NON_DEL_5800	0.009	0.005	0.010	0.015	0.02	0.025	0.030	0.035
CORE SET CTS	49.50	49.50	49.50	49.50	49.50	49.50	49.50	49.50
HYBRID CORRECTION	0.21	0.10	0.19	0.28	0.36	0.44	0.52	0.59
HYBRID CTS	**49.71**	**49.60**	**49.69**	**49.78**	**49.86**	**49.94**	**50.02**	**50.09**

Within confidence interval (CI) of core CTS value

Outside CI of core CTS

Observations from indicative hybrid approach analysis

Based on the indicative hybrid approach analysis and the report from Zachary and Wilson, we made the following observations:

- Using the probabilities (0.011, 0.011, 0.009, 0.009) estimated for the extreme cases in this example, the outcome only changed by ~0.2 GW.
- Based on the findings of the report, we suggested as a "rule of thumb", if the extreme set CTS range is within +/- 5 GW of the estimated core set LWR outcome and the average probability of cases in the extreme set is below 0.02, the hybrid approach is unlikely to produce a material change to the core LWR outcome.
- This "rule of thumb" appeared to work in the indicative analysis: since the average probability of cases in the extreme set was well below 0.02 and the hybrid approach did not produce a correction to the core LWR outcome outside of the confidence interval (+/- 0.4 GW) of the core CTS.
- To shift the result outside of the confidence interval would have required an average probability for an extreme case of around 0.25 or higher, which would be approaching the probability of an average case in the core set.
- If we had included even more extreme cases (e.g. combinations of 3 independent sensitivities or "black swan" events), these could have been more than +/- 5GW outside the core CTS value, but the probabilities would have been very low for such cases, resulting in no material change to CTS.
- Given that the LWR outcome did not appear to change materially, following discussions with BEIS, Ofgem and the PTE, we agreed not to implement the hybrid approach without further research.

A.7.4 Capacity to Secure Charts

The impact of over or under securing is not symmetrical. The cost of under securing capacity is much higher than over securing due to the non-linear relationship between unserved energy cost and capacity cost. This happens because as the capacity secured reduces, the number of half-hours where demand exceeds available capacity grows exponentially and the unserved energy increases at an even faster rate.

Figures 35 and 36 for 2021/22 and 2018/19 respectively show how the total cost varies for different potential levels of capacity secured for the scenarios as well as the most optimistic and pessimistic sensitivities modelled for each year.

These charts of total cost against secured capacity show costs falling steeply as energy unserved falls but once there is sufficient capacity secured the unserved energy cost is low and costs start to grow at a linear rate as extra capacity is added (since a constant unit capacity cost has been used). The optimal capacity for any one case will be around the bottom of the total cost curve for that case.

Figure 35: Cost v Potential Capacity to Secure Levels 2021/22

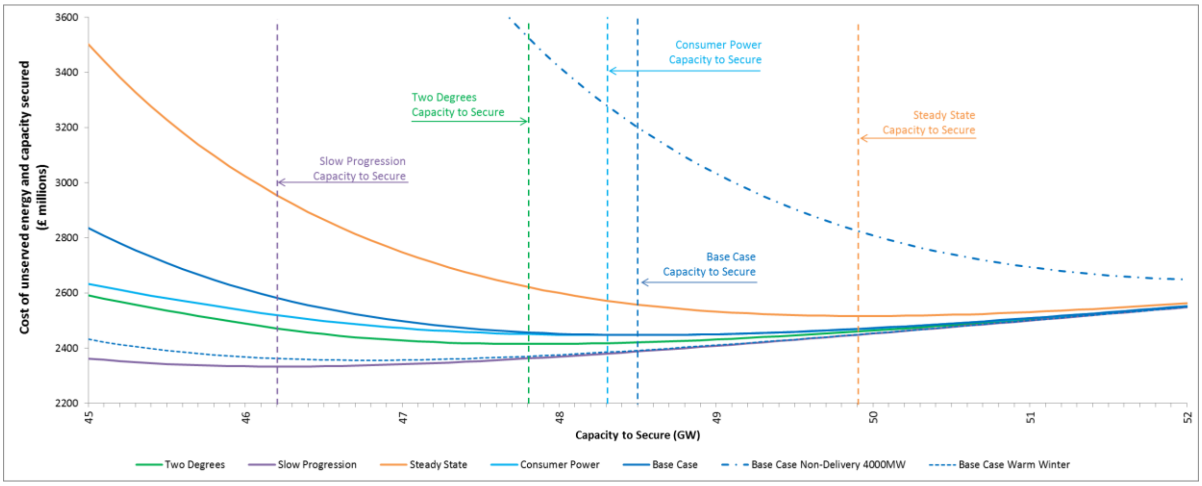
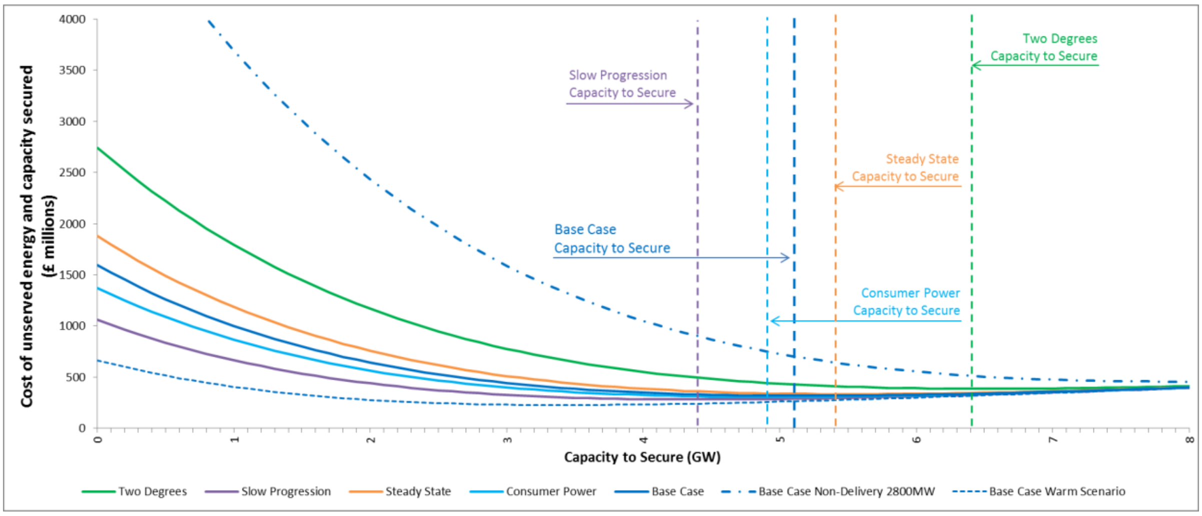


Figure 36: Cost v Potential Capacity to Secure Levels 2018/19

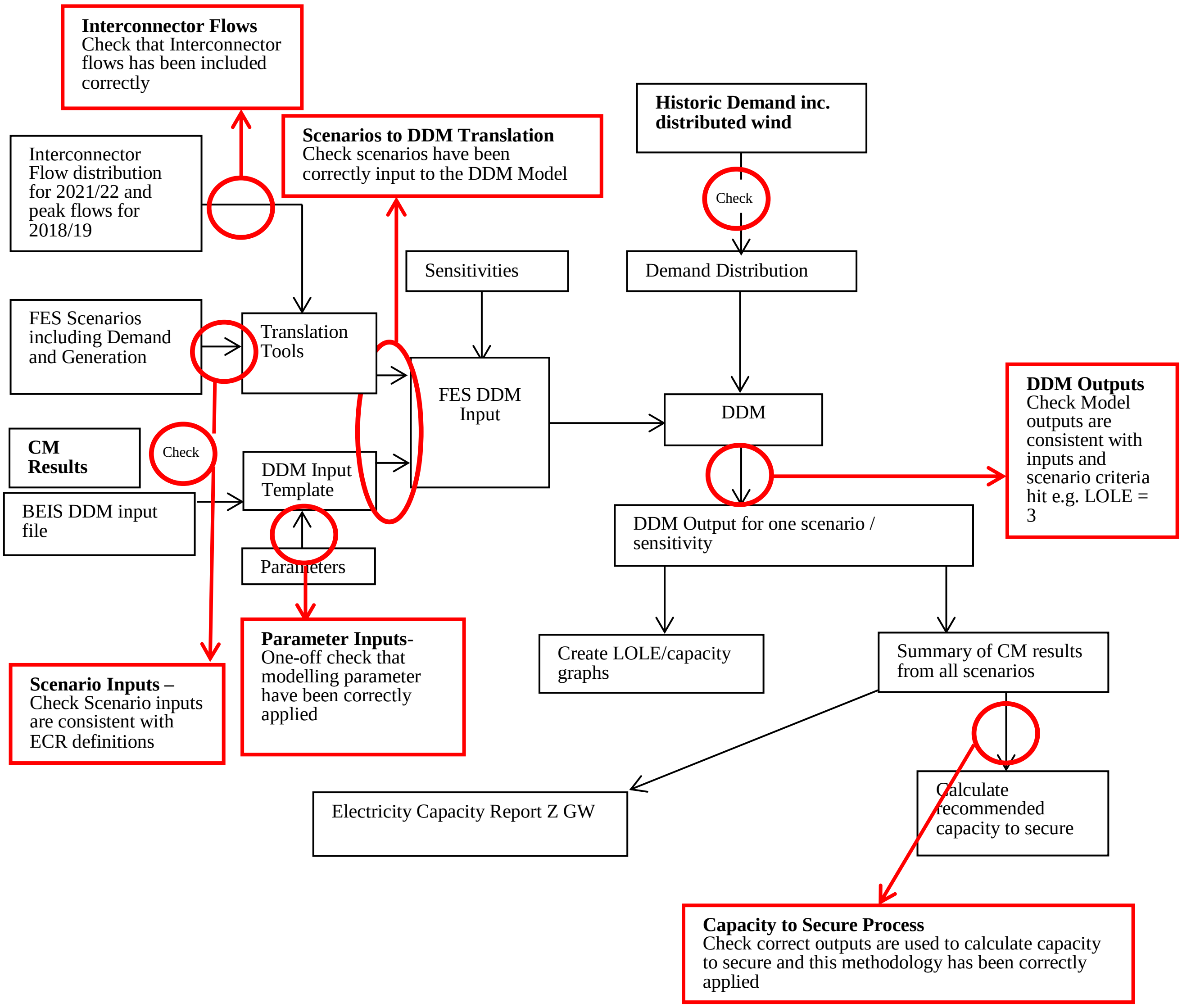


A.8 Quality Assurance

When under taking any analysis National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid has worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process[50]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have QA undertaken when that project "stage gate" (such as inputting data in to a model) is met. This approach allows any issues to be quickly identified and rectified.

The high level process and the points within the process where QA checks have been undertaken are shown in the following process diagram:

Figure 37: QA checks process diagram for each target year



[50] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358356/DDM_QA_Summary.pdf

The QA checks above (bordered in red) are centred on the points in the process where data is transferred from one model, or system, to another along with the model outputs. The QA is undertaken in this way as it is more straight-forward to follow which QA step is being applied at which step in the process. These steps are:

1. **Interconnector flows** – Check the interconnector flow assumption/distribution

2. **Scenario inputs** – Check the model input assumptions

3. **Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind** – Check the model setup assumptions

4. **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model

5. **DDM Outputs** - Check model outputs are consistent with inputs and scenario criteria

6. **Capacity to Secure Process** – Check the inputs and outputs used to determine a range and recommended capacity to secure

Below is detailed QA process for each of these steps.

Interconnector flows

Interconnector flow assumptions / distributions have been discussed with BEIS, PTE and Ofgem at various bilateral meetings. We have also consulted the results with the industry at various stakeholder events. For each scenario, the modelled interconnector flows and results are checked throughout the QA checklist process.

Scenario Inputs

The FES process is driven by extensive stakeholder engagement51, workshops and bilateral meetings; this engagement leads to the creation of the scenarios. The constituent parts of the scenarios, for example electricity demand, are subject to internal challenge and review to ensure that they consistent and robust. Sign off is then required at senior manager level and formal sign off is then required from the SO Executive Committee. The assumption and outputs will be published in the annual FES document on July 2017.

For the purposes of the ECR process a check is undertaken that the inputs are consistent with the requirements of the ECR process.

Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind

The parameters are set to ensure that the model runs as is required for the ECR process. These parameters are checked and documented by analyst to ensure that they are correct and then a final template is created (with a backup) which all runs are then based on. This step also includes checking of the inputs like historic

[51] http://fes.nationalgrid.com/media/1195/stakeholder-feedback-document-fes-2017.pdf

demand, demand met by distributed wind and CM Results are correctly included in the model.

Scenarios to DDM Translation

The tool for translating the FES scenarios into DDM has been documented and available for scrutiny by BEIS and the PTE. The tool includes checks that the correct information has been inputted to the model.

DDM Outputs

Each run of the analysis, including inputs and outputs, has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and the ECR project. These documents and the associated files have been shared with BEIS to allow it to perform its own QA process.

QA Check List Process

Each run of the analysis, including inputs and outputs, is checked and documented internally by an analyst through a QA Check List process.

Capacity to Secure Process

Once all the runs have been completed the key results are used to determine the recommended capacity to secure using Least Worst Regret (LWR) tool. This process has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and ECR project. Again, these files have been shared with BEIS to allow it to perform its own QA process.

DDM model

In addition to checks described in above figure, DDM model has been reviewed and had QA performed a number of times including:

- A peer review by Prof. Newbery and Prof. Ralph
- A review of the code by PwC
- Internal reviews by BEIS

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of DDM for ECR. In previous years, the owners of DDM, consultants Lane Clark & Peacock (LCP[52]), were asked to ensure that National Grid was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between National Grid and LCP to discuss in detail the modelling being undertaken. This highlighted some minor issues which have been resolved. LCP produced a report of their QA process. The report concluded that National Grid is using the model correctly and correctly interpreting the output results.

[52] http://www.lcp.uk.com/

Process Overview and Governance

The process will be overseen by the PTE and they will review and report on the overall process. Internally the process has governance under Director UK System Operator.

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