National Grid EMR Electricity Capacity Report

31st May 2016 (submitted to DECC)

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

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Contact

Any enquiries regarding this publication should be sent to National Grid at emr@nationalgrid.com

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 2017/18 and 2020/21.

In addition we have been asked by Department of Energy and Climate Change (DECC) to provide, for information only, an early snapshot of an indicative requirement for the 2018/19 T-1 auction that will improve transparency and help market participants understand their options more clearly.

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.

Chapter 2 of this report aims to describe the modelling approach and the tools utilised. Chapter 3 of the report describes the individual scenarios and sensitivities modelled. Chapter 4 covers the modelling and recommendation for the de-rating factors to apply to interconnectors and conventional plants. Chapter 5 contains results from the scenarios modelled, along with a recommended capacity to secure for the 2020/21 T-4 auction. Chapter 6 provides recommended capacity to secure for the 2017/18 early auction. Chapter 7 provides an indicative capacity requirement for the 2018/19 T-1 auction. Finally the Annex contains the details behind the assumptions, the modelling approach, a least worst regret example and the quality assurance process.

1.1 Modelling Process

A key aim of this analysis is to provide advice to the Government on how different scenarios would impact on its objectives, so that it can take informed decisions. The modelling approach adopted for the EMR Capacity Market analysis is described in detail in the Annex, including the data, assumptions and models utilised. The scenarios and sensitivities run through the model are detailed in Chapter 3. The scenarios and sensitivities investigated offer a range of likely demand and generation outcomes which are intended to meet the required security of supply as set out by Government’s Reliability Standard.

The principal modelling tool National Grid has used is a fully integrated power market model, the Dynamic Dispatch Model (DDM). The model enables analysis of electricity dispatch from power generators and investment decisions in generating capacity to at least 2035. The model performs runs based on sample days, including demand load curves for both business and non-business days. Investment decisions are based on projected revenue and cash flows allowing for policy impacts and changes in the generation mix and interconnection capacity. The full lifecycle of power generation plant is modelled through to decommissioning endeavouring to replicate the real world investment decisions without perfect foresight as the model isn’t optimised.

In order to provide the most complete view of the implications of the alternative scenarios and sensitivities (see the results in Chapter 5, 6 & 7), National Grid has also built a “Least Worst Regret (LWR)” tool to calculate the appropriate level of capacity to secure to meet the Reliability Standard that minimises the regret cost implications of that decision.

National Grid has also considered the recommendations included in the Panel of Technical Experts (PTE) report on the 2015 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 DECC, PTE and Office of Gas and Electricity Markets (Ofgem) to enable them to scrutinise the modelling approach and assumptions utilised.

1.2 National Grid Analysis Delivery Timeline 2016

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

The work was carried out between September 2015 and May 2016 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 to 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 2015
- Development projects completed by March 2016
- Production plan developed in February 2016
- Modelling analysis February to May 2016
- National Grid's ECR is sent to DECC before 1st June 2016
- Publication of ECR in line with DECC publishing auction parameters planned by 1st July 2016

1.3 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 of coal plant, station peak availabilities, weather, wind levels and peak demand forecast range (based on the Peak National Demand Forecasting Accuracy (DFA) Incentive[1]) plus interconnector flow sensitivities (for 2018/19 only). In addition to the four FES scenarios and National Grid's Base Case (see Chapter 3), a DECC Scenario has been included for information but was excluded from the LWR calculation to ensure the recommendation is fully independent.

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

Scenarios & Base Case

- Base Case (5 year forecast to 2020/21 then Slow Progression from 2021/22 onwards
- FES Gone Green (GG)
- FES Slow Progression (SP)
- FES No Progression (NP)
- FES Consumer Power (CP)

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 2020/21, 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.

The Base Case also assumes that some capacity contracted in previous T-4 auctions is not able to honour its awarded contracts. For example, the Base Case assumes early closures of some contracted coal plants (due to the challenging economic climate for coal station operators) and the slippage of some new build capacity. The volume of such capacity totals 4.3 GW in 2018/19 and 2.9 GW in 2020/21.

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 3.11 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 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[2] 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).

1.3.1 2020/21 T-4 Auction Recommendation

Sensitivities

The agreed sensitivities to model (see 3.11 for more details) for 2020/21 cover non-delivery of coal plant, weather, plant availability 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 Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)

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

- Non Delivery (NON DEL): 9 sensitivities in 400 MW increments (for granularity) up to 3600 MW.

Results

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is an initial capacity to secure for 2020/21 of 49.5 GW (49.48 GW before rounding) based on the Consumer Power scenario. As this is a FES scenario, a small adjustment is required to bring it into line with the DFA Incentive by selecting the nearest Base Case sensitivity based on the DFA Incentive demand level (See Section 2.6.3 for more details). In this case the nearest sensitivity is the 2000 MW non-delivery sensitivity (49.65 GW before rounding) that is marginally closer than the 1600 MW non-delivery sensitivity (49.25 GW before rounding)

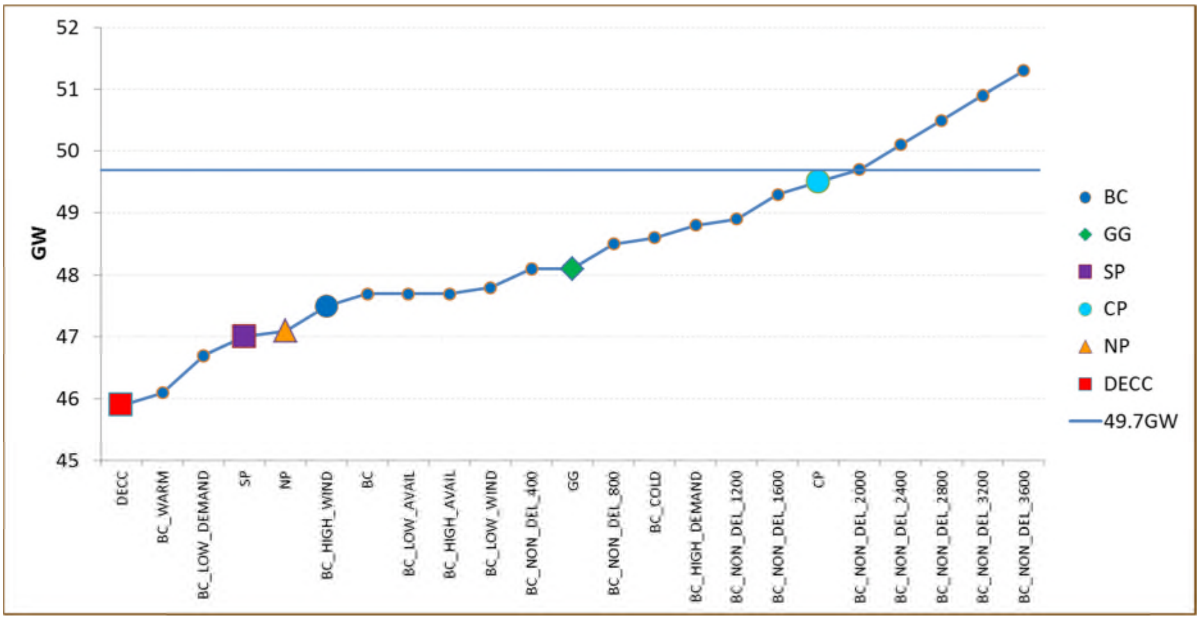
This leads to a recommended capacity to secure for 2020/21 of **49.7 GW** set by the requirement of the Base Case 2000MW non-delivery sensitivity. This does not take account of a different clearing price to net CONE resulting from the auction as our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost and also excludes any capacity secured in earlier auctions for 2020/21 that is assumed in the Base Case.

In general, when compared to the analysis for 2019/20 in the 2015 ECR, the 2016 scenarios and sensitivities for 2020/21 contain higher levels of CM-ineligible de-rated capacity at peak due to higher contribution from renewables (see Annex for breakdown), in part due to the new offshore power curve (see 2.6.1), as well as higher levels of assumed ineligible autogeneration below 2 MW[3]. However the reduction in total CM-eligible capacity requirement due to higher levels of ineligible capacity is offset by using a wider range of non-delivery sensitivities that increases the requirement in the LWR analysis. The warm winter sensitivity is key to the LWR result, as it is the sensitivity that sets the highest regret cost for the recommended capacity level (see Annex for more details on how regret costs are determined in the LWR calculation).

The following chart illustrates the full range of potential capacity levels (from National Grid scenarios, Base Case and sensitivities) plus the DECC scenario and identifies the Least Worst Regret recommended capacity. Note that National Grid's recommendation concentrates on the target capacity alone. The values for all of the auction parameters will be determined by the Secretary of State.

[3] 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: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2020/21



Recommendation

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 the scenario was to occur in 2020/21, then the LOLE may be greater than 3 hours. This could increase the chances of deploying mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently/in higher volumes to avoid 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 49.7 GW would result in 18 out of 22 National Grid cases (plus the DECC scenario) being covered.

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 National Grid recommended capacity auction requirement, a number of adjustments to the total recommended figure will need to be made which are detailed in Chapter 5.

Therefore, the recommended total capacity to secure through the 2020/21 auction will be:

- 49.7 GW minus any adjustments

1.3.2 2017/18 Early Auction Recommendation

Sensitivities

The agreed sensitivities to model (see 3.11) for 2017/18 cover non-delivery, weather, plant availability 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 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.

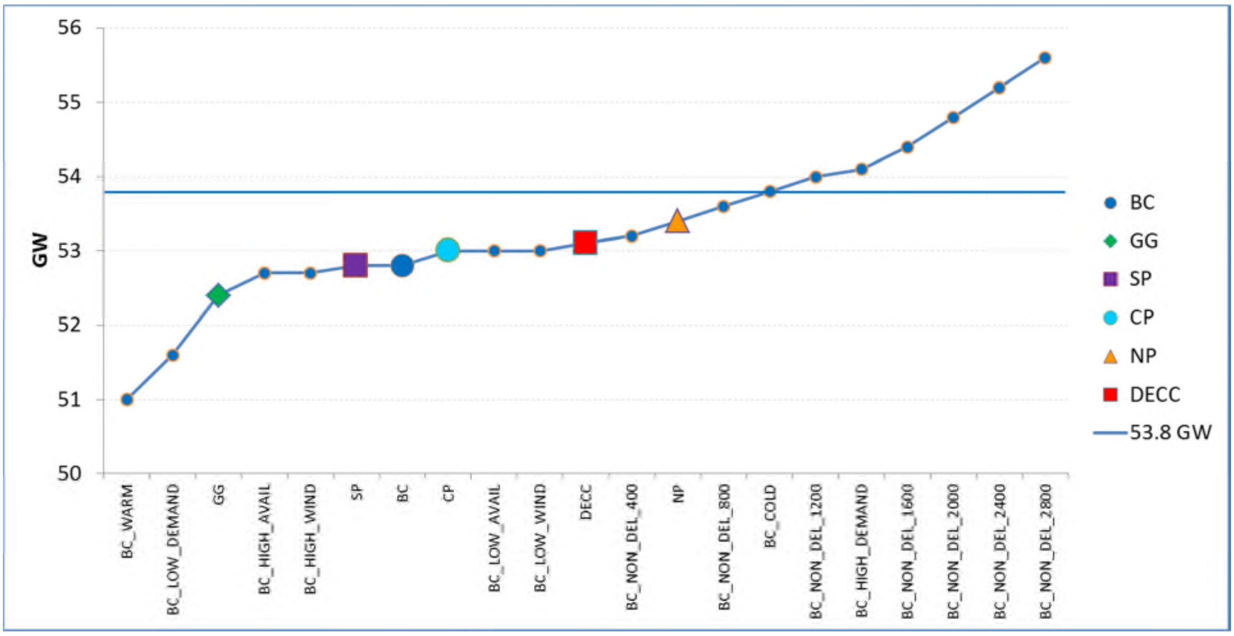
Results

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 2017/18 of **53.8 GW** set by the requirement of the Base Case Cold Winter sensitivity. This does not take account of a different clearing price resulting from the auction.

In general, when compared to the analysis for 2018/19 in the 2014 ECR, the 2016 scenarios and sensitivities for 2017/18 contain higher levels of CM-ineligible de-rated capacity at peak due to higher contribution from renewables (See Annex for breakdown), in part due to the new offshore power curve, as well as higher levels of assumed ineligible autogeneration below 2 MW. However the reduction in total CM-eligible capacity requirement due to higher levels of ineligible capacity is offset by higher peak demands and by using a wider range of non-delivery sensitivities that increases the requirement in the LWR analysis. The 2800 MW non-delivery sensitivity is the key to the LWR result as it is the sensitivity that sets the highest regret cost for the recommended capacity level (see Annex for more details on how regret costs are determined in the LWR calculation).

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

Figure 2: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2017/18



Recommendation

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 the scenario was to occur in 2017/18, then the LOLE would be greater than 3 hours. This could increase the chances of deploying mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently/in higher volumes to avoid 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 53.8 GW would result in 14 out of 20 National Grid cases (plus the DECC scenario).

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 early auction capacity requirement, a number of adjustments to the recommended figure will need to be made which are detailed in Chapter 6.

Therefore, the recommended total capacity to secure through the 2017/18 early auction will be:

- 53.8 GW minus any adjustments

1.3.3 2018/19 Indicative Requirement for T-1 Auction

Sensitivities

The agreed sensitivities to model (see 3.11) for 2018/19 cover non-delivery, weather, plant availability, demand and peak interconnector 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): 9 sensitivities in 400 MW increments up to 3600 MW.
- 750 MW Continental interconnector imports (IC 750IMPORTS): 300 MW net GB flow (including 450 MW exports to Ireland)
- 1500 MW Continental interconnector imports (IC 1500IMPORTS): 1300 MW net GB flow (including 200 MW exports to Ireland)
- 2250 MW Continental interconnector imports (IC 2250IMPORTS): 2500 MW net GB flow (including 250 MW imports from Ireland)
- 3000 MW Continental interconnector imports (IC 3000IMPORTS): 3500 MW net GB flow (including 500 MW imports from Ireland)

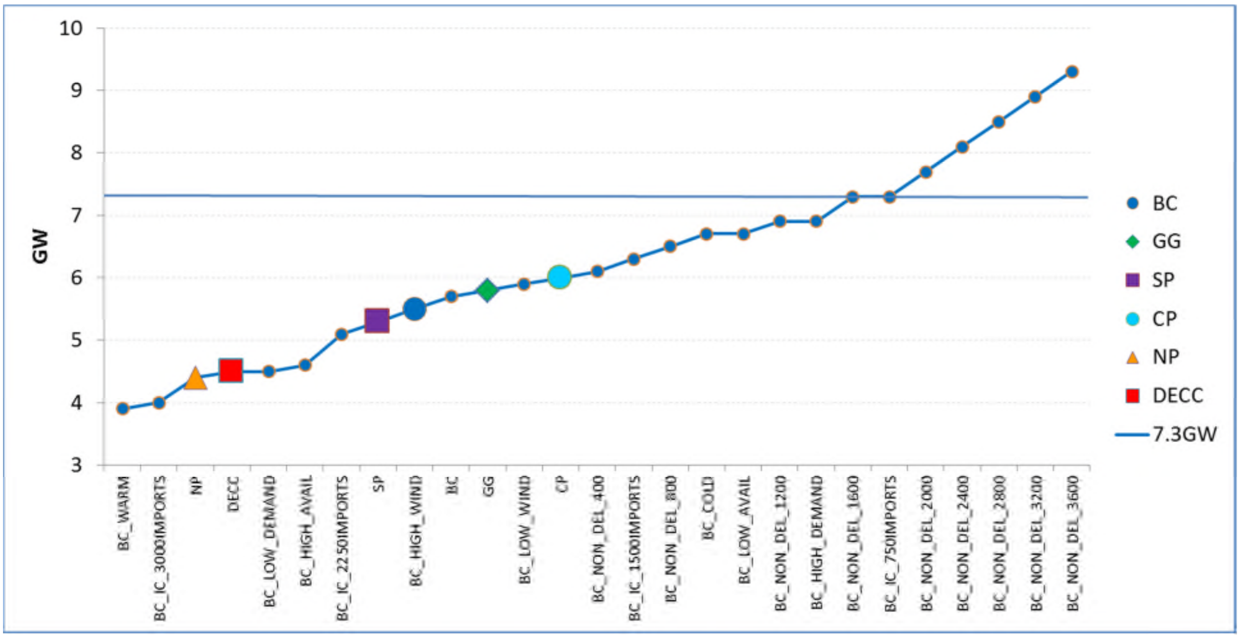
Results

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is an indicative capacity to secure for 2018/19 of **7.3 GW** set by the requirement of the Base Case 1600MW sensitivity (and also the 750 MW Continental Imports sensitivity). This does not take account of a different clearing price to net CONE resulting from the auction as our indicative target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost.

In general, when compared to the analysis for 2018/19 in the 2014 ECR, the 2016 scenarios and sensitivities for 2018/19 contain higher levels of CM-ineligible de-rated capacity at peak due to higher renewables contribution (see Annex for breakdown), higher levels of assumed opted-out or ineligible (below 2 MW) autogeneration, higher imports and over-securing in the 2018/19 T-4 auction. However the reduction in the T-1 CM-eligible capacity requirement due to higher levels of ineligible capacity is more than offset by assumed non-delivery in the Base Case, the contracted capacity in the T-4 auction being greater than de-rated TEC, "opted out but operational" plant closing and higher peak demands (See Chapter 7 for more details).

The following chart illustrates the full range of potential capacity levels (from National Grid scenarios and sensitivities) plus the DECC scenario and identifies the Least Worst Regret indicative capacity. Note that this concentrates on the indicative target capacity alone.

Figure 3: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2018/19



Indicative Requirement

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 the scenario was to occur in 2020/21, then the LOLE may be greater than 3 hours. This could increase the chances of deploying mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently/in higher volumes to avoid 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 7.3 GW would result in 21 out of 26 National Grid cases (plus the DECC scenario) being covered.

The indicative capacity in this report 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 requirement, a number of adjustments to the indicative figure will need to be made which are detailed in Chapter 7.

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

- 7.3 GW minus any adjustments

Note that this indicative capacity may change when the LWR analysis is updated next year. For example, if the closure of 2.7 GW of contracted coal capacity in 2018/19 assumed in the Base Case did not occur, the 7.3 GW indicative requirement would potentially drop by 2.7 GW to 4.6 GW.

1.4 Interconnected Countries De-rating factor Ranges

Table 1: De-rating factor ranges shows the recommended ranges for de-rating factors in 2017/18 and 2020/21 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 undertaken by Baringa using their pan-European market model and Pöyry's analysis on historical performance. The top of the de-rating factor ranges are set by the Baringa modelling with Pöyry's analysis of seven historical years setting the bottom of the ranges for all but Ireland in 2020/21. We have assumed that by 2020/21 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 90th percentile from the Baringa's results to set the lower bound. This assumption is not certain and if market coupling does not develop in Ireland then the Pöyry history would 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.

Table 1: De-rating factor ranges

%'s		France	Netherlands	Ireland	Belgium	Norway
2017/18	High	86	82	58	-	-
2017/18	Low	45	70	2	-	-
2020/21	High	88	82	50	92	96
2020/21	Low	45	70	25	65	76

2. The Modelling Approach

The modelling analysis has been undertaken by National Grid with ongoing discussions with DECC, Ofgem and DECC's EMR Panel of Technical Experts (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)[4]?

In order to answer this question it was agreed, following consultation with DECC and their PTE, that the Dynamic Dispatch Model (DDM)[5] was an appropriate modelling tool. This maintains consistency with the modelling work undertaken by DECC. The DDM has the functionality to model the Capacity Market with the following sections describing this 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[6], 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)[7], 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. A DECC Scenario has also been included in the analysis, which provides a point of comparison between DECC's own analysis and that contained in this report. The DECC Scenario is based on the reference scenario from the 2015 Energy and Emissions Projections[8] (EEP). Annual demand projections are still consistent with 2015 EEP, but for the purpose of the ECR there have been some amendments to include the results of the December 2015 Capacity Auction and to align with National Grid's 2015 ACS peak.

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)

Sensitivities are then created around the Base Case to ensure consistency with National Grid's Peak National Demand Forecasting Accuracy (DFA) Incentive[9].

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[4] 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 SO balancing contracts have been exhausted.

[5] DDM Release 5.0.0.0 was used for this analysis

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

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

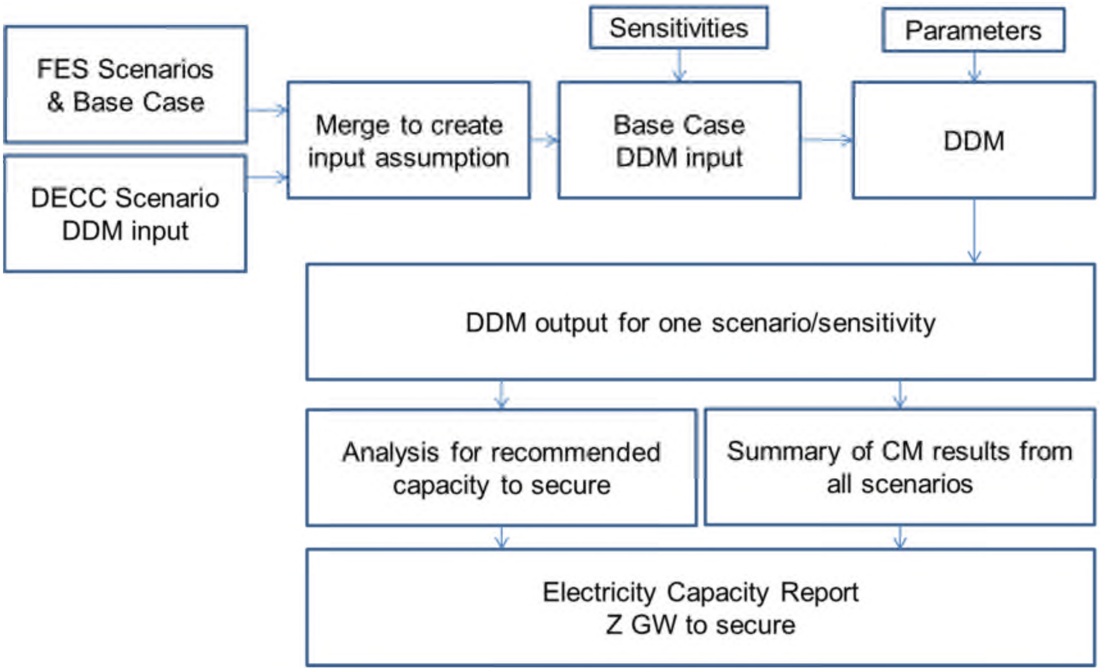
[8] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015

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

Separate model runs were carried out for years 2017/18, 2018/19 and 2020/21 as the treatment of interconnectors and sensitivities applied to each of these years was different.

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 2017/18 and 2020/21 with an indicative requirement for 2018/19. This process is detailed in the Annex.

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



2.2 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 one to one 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 in line with our licence condition. The document, published annually in February, shows how stakeholder feedback directly 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 engages with stakeholders to explain its role in relation to EMR through the CM Implementation workshops throughout the year.

2.3 High Level Assumptions

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

The starting point for the DDM input modelling assumptions was the set of assumptions used in the latest DECC modelling e.g. generation levelised costs. However, the key inputs/assumptions are taken by aligning the modelling to the new 2016 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.

2.3.1 Interconnector Assumptions

As part of the UK's State aid approval for the Capacity Market, interconnectors are eligible to participate in the CM since the 2015 auction. As such, the UK has committed to include interconnectors in the 2017/18 early CM auction as they provide an important contribution to security of supply through access to more diverse generation capacity. 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 probabilistic modelling in a similar way to generation technologies i.e. based around a set of flow distributions obtained from Baringa's pan European electricity dispatch market model.

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.

2.3.2 Station Availabilities

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

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[10]. 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.[11]

Table 2 shows the station availabilities based on the last 7 winters (2009/10 – 2015/16) for each type of generation. The mid availability is defined as the mean of each of the last 7 winter's availability values. The low and high values are defined as this mean plus/minus one standard deviation (of the 7 estimates).

Table 2: Low, Mid and High Availabilities

Generation Type	Low	Mid	High
CCGT	86%	88%	90%
OCGT	92%	94%	96%
Coal	85%	87%	89%
Nuclear	80%	84%	89%
Hydro	79%	86%	91%
Oil	75%	85%	95%
Pumped Storage	94%	96%	98%

Previous comments[12] from DECC'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.

Subsequently, 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 types CCGT, OCGT, coal and nuclear, Arup provided an availability assumption. The following table shows the two views of availabilities

Table 3: Availability Comparison

Generation Type	National Grid	Arup
CCGT	88%	87% -93%
OCGT	94%	94%
Coal	87%	87%
Nuclear (Existing)	84%	77%

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

[10] 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
[11] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34154
[12] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267624/Annex_E_-_PTE_draft_report_FINAL.pdf

Table 4: Availabilities Used

Generation Type	Availability %
CCGT Pre 2018/19	88%
CCGT 2018/19	88%
CCGT 2020/21	90%
CCGT Post 2020/21	90%
OCGT	94%
Coal	87%
Nuclear (Existing)	84%

Given the current plant economics, age and mode of operation it is not surprising that GB CCGT availabilities are at the lower end of the international range. The increasing CCGT availability reflects the introduction of the Capacity Market and the general three year maintenance cycle for the CCGT fleet to improve its availability once spark spreads rise. The last two winters in particular, have seen rising availabilities, which may be due to more favourable economics for gas compared to coal, as well as investment in plant maintenance. This provides further support for the move towards higher availabilities that National Grid has previously assumed for CCGTs post 2018/19.

The 90th percentile of demand has been used for CCGTs rather than the 50th percentile since in recent years CCGT availabilities have been lower than expected (due to low spark spreads). Filtering observations out to see higher percentile demand availability removes most of the commercial and planned outages that a plant may have chosen to take historically and gives a figure of nearly 88% (rather than 85% based on the 50th percentile of demand). While this significantly reduces the number of data points in the analysis, the approach is justified because the availabilities should reflect what stations can be expected to deliver when they are needed. Therefore, filtering out historic data associated with outages that plant may have chosen to take seems a reasonable approach. By 2017/18, it is expected that spark spreads will be at a level to assume availabilities start to rise and reach the internationally benchmarked level of around 90% by 2020/21. The availabilities of other types of generation showed very little variation between the 50th and 90th percentile of demand. This may reflect that their plant economics have been more favourable than CCGTs in recent years and so may not have chosen to take commercial or planned outages at high demand periods. Therefore, the 50th percentile of demand was used for all other types of generation as this involves using a larger data set and there were no other reasons to change.

Some views have been expressed that the CCGT availability is still too low and still includes commercial and planned outages as few very tight system periods have occurred. However, the assumptions behind station availabilities need to be evidence-based. There may be several reasons why stations take planned outages at times of high demand, some of which they may be unavoidable. Therefore, this needs to be reflected in the availability value until we have evidence otherwise. Failing to include this behaviour means that the availability values will be artificially inflated above the international standards.

When National Grid's calculated availabilities are compared to Arup's internationally benchmarked figures, the net effect on today's level of de-rated capacity across all technologies has very little impact at around 0.1GW. Consequently, it is reasonable to suggest that the two methods validate one another and the figures for GB are evidence-based, credible and auditable.

The nuclear availability from Arup was considered to be at the low end of the range. National Grid has gathered information from Grid Code obligations and stakeholder feedback, not available to Arup, to inform the final discussion on nuclear availability.

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.

During such consultations our assumptions of independence of generating units was questioned, in that the unavailability of one generating unit may be linked to the availability of one or more other units. If some dependence is assumed, this could put downward pressure on the availability figures. However, further detailed analysis would need to be carried out in order to understand the implications of changing such assumptions. This would require consultation with DECC and the PTE, with a view to undertaking a development project for next year.

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 any 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 system. 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.

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 the analysis carried out by Baringa (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.

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 5, 6 & 7 for the details for the details of how de-rated capacity changes with variations in availability assumptions.

2.4 DDM Outputs Used in the ECR

For the purpose of the ECR, the key outputs utilised from the DDM for each year modelled from 2017/18 to 2030/31 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

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 2017/18, 2018/19 and 2020/21, the ECR also utilises the expected energy unserved (EEU) values for potential de-rated capacity levels in all three years (see Chapters 5, 6 & 7 for more details).

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

2.5 PTE Recommendations

In the PTE's "Final Report on National Grid's Electricity Capacity Report" – June 2015[13] they identified a number key issues, themes and recommendations which National Grid agree need further investigation and have therefore undertaken a number of development projects as part of this year's process:

- Additional analysis should be undertaken to understand the potential contribution from DSR and distribution connected generation **(Recommendation 11):**

  As part of the 2016 FES process we have carried out extensive searches across a range of sources to obtain a more accurate figure for the levels of installed distribution connected generation. This has provided detailed capacity figures for all technologies but unfortunately not their levels of generation. We are currently in negotiation with ElectraLink (a commercial company owned by a group of Distribution Network Operators (DNOs)) to secure half hourly data for the last few years for each distribution connected plant. This data should provide insight into how patterns of generation have changed over the recent past as financial incentives have improved and should deliver the increased knowledge and understanding the PTE sought. This latter point will address the follow up to the PTE's **Recommendation 10**

[13] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/438714/PTE_2015_ECR_Report_final.pdf

from their 2014 report which requested more analysis on distributed generation availabilities.

National Grid has been working closely with industry via its Power Responsive campaign to help inform and facilitate greater participation in both true DSR (i.e. demand shifting or demand reduction) and distributed generation. This campaign has included extensive engagement, industry workshops and published documents all highlighting the financial incentives and ways to participate. This campaign appears to have successfully contributed to the increased participation of both DSR and distributed generation seen in the market during 2015/16.

- The PTE expressed concerns over the inclusion of extreme weather events as sensitivities within the LWR process as the LOLE calculation already allows for such events and therefore there was a danger of double counting.

  To help address this concern we commissioned academic consultants from Durham University and Heriot Watt University (Zachary, Wilson & Dent) to investigate the statistical uncertainty around the non-linearity of impact on LOLE. This work centred on the fact that while LOLE is a long run average metric, it was only the most extreme observations that make made any significant contribution to it and hence uncertainty associated with these estimates was crucial to understanding uncertainty as a whole. For example, a major source of uncertainty in statistical analysis results from the dramatic effects of varying winter severity. It is far from clear that the probability of a severe winter in a future year under study is well approximated by the fraction of severe winters in the historical data (10 years), and for this reason alone it makes sense to also report estimates of LOLE, etc., conditional on winter severity (as it standard practice in many other countries). The academic work concluded that this is not a case of double counting.

  Consequently, it is fair to say that the PTE's comments are valid when using a long series of historical data (note for average weather conditions the MET Office uses 30 years of data); however, as we are only using 10 years it is therefore not long enough to say with any certainty (without some further detailed analysis which could be addressed by a development project for next year) that it is representative of future years being studied. Hence we proposed to DECC and the PTE that we need to address this uncertainty in weather by including a cold weather sensitivity based on a recent non-extreme cold winter e.g. 2010/11. Given the supporting evidence of this academic research the PTE agreed to the inclusion of the cold and warm weather sensitivities in the 2016 analysis. Note that we wouldn't consider using a long series of demand as that wouldn't be representative of demand in future years as the make-up of demand was considerably different 20 years ago e.g. manufacturing versus service industries.

- National Grid should expand its analysis of loss of load events to take account of the volume, frequency, duration, forewarning and predictability of loss of load events **(Recommendation 12):**

  This recommendation can be addressed in two parts; the modelling of loss of load events (for which in the past we have undertaken some work for Ofgem) and the details around emergency procedures that would be utilised leading up to controlled disconnections by the DNOs.

The functionality of the DDM version currently utilised for the Capacity Market work doesn't produce information on frequency and duration as it is time collapsed rather than sequential. While a module of DDM has a sequential capability there are limited reliable data sources currently available to enable the model to be effectively run. Also the run time of any sequential model would need to be carefully considered due to the practicality of delivering the analysis given the limited time available to undertake and deliver the work. However, we have run our own time collapsed Capacity Assessment model in a way that enables an approximation of frequency and duration metrics to be calculated. When we shared this analysis with DECC and the PTE they felt that while interesting the frequency metrics could be misinterpreted, as verification required sequential modelling, and as it doesn't impact the resulting capacity to secure figure, we agreed not to re-produce the analysis in our report.

The PTE have presented work undertaken by Imperial College London that modelled the GB market sequentially using a range of data including a Institute of Electrical & Electronic Engineers (IEEE) dataset to produce frequency and duration statistics. This work provided interesting insight in to the potential shape of loss of load events under a 3 hour loss of load expectation Reliability Standard. Any future development projects will centre on how these findings could be potentially translated into running the DDM in a practical way and ensure appropriate model run times to enable timely delivery of outputs. Consequently, we would be happy to work with the PTE and DECC to agree a development project for the autumn to review any potential options.

To address the second part; in addition to providing information on the mitigating actions the System Operator can take we also provided a summary of the Demand Control operating code, Demand Control decision and communication process, Demand Control instruction formats, data on the last occasions when it was utilised, data on historical Notification of Inadequate Supply Margin (NISMs) and an overall summary. The PTE also were interested in understanding the process by which DNOs disconnect consumers which unfortunately we were unable to provide as that is something each DNO will undertake (potentially using different approaches which best suit their particular network), not National Grid.

While all the above information is important, it has no effect on our capacity requirement recommendation as that is measured before any mitigating or emergency actions are taken. There are two practical reasons for this; firstly, these actions aren't firm and therefore can't be guaranteed and secondly, these are emergency actions and shouldn't be planned to be utilised otherwise they are no longer emergency actions. Note all ancillary service contracts we have are assumed to be utilised in the calculation to meet the Reliability Standard with these mitigating and emergency actions being on top of those.

- Concerns over the value of lost load (VoLL) being utilised in the LWR calculation not reflecting the lower cost of mitigating actions and therefore distorting the calculation with a potential for securing too much capacity.

There are two aspects to consider around these concerns; firstly, the process by which VoLL was estimated and secondly, the wider context around how VoLL is used within the Reliability Standard.

We agree with the PTE that in reality the VoLL would start lower than the figure used for the LWR analysis of £17,000/MWh as mitigating actions are taken, e.g. voltage reduction, but would then progressively increase as further actions are taken before rises above £17,000/MWh, as loads are disconnected. Consequently, when London Economics estimated the average VoLL they took account of the increasing cost of different components of VoLL at the level of customer disconnections. There is inherent uncertainty in setting the level of VoLL and it is dependent on the questions asked of consumers and whether the wider economic impacts are considered. The determination of VoLL is currently outside the scope of this analysis.

The other metric utilised within the LWR calculation is the Cost of New Entry (CONE) which is also based on an average figure when in reality it would also have a cost/supply curve. Consequently, adjustments in VoLL cannot be considered in isolation without considering CONE. As a development project we asked our academic consultants from Durham University and Heriot Watt University (Zachary, Wilson & Dent) to review the LWR process and one of their conclusions was that the ratio of VoLL to CONE would need to remain consistent with that used when defining the Reliability Standard (i.e. ratio of close to 3 (£47/kW/yr / £17,000/MWh). This means that if VoLL was reduced then CONE would also need to be reduced to maintain the same ratio otherwise the analysis would be basing its calculations on a different Reliability Standard.

In addition to enable the LWR decision tool to run effectively we need a single value for both VoLL and CONE. To try and use cost/supply curves that vary these values would prove difficult to implement as it would make the calculation extremely complex but more importantly would have no impact on the recommended capacity to secure as the ratio of the two would always need to be 3.

DECC undertook some analysis in this area and as a result of the academic research outlined above, concluded that any review of VoLL would need to align with the review of the Reliability Standard to be undertaken which will consider a more sophisticated representation of both VoLL and CONE.

- Develop a pan-European dispatch model with the functionality to simulate the behaviour of interconnectors in a variety of market coupled scenarios **(Recommendation 13):**

  To support our interconnector modelling for FES and EMR we commissioned Baringa to undertake analysis of annual and peak flows across interconnectors utilising their Plexos pan-European model with flows being determined predominantly by the relativity of generation short run marginal costs (SRMCs) in each country. This modelling was enhanced from that used last year by the inclusion of scarcity premia, number of historical years utilised and a larger number of simulations. More detail on this can be found in Chapter 4.

For our FES and EMR analysis in 2017 and to support our role in Integrated Transmission Planning & Regulation (ITPR) we have procured a pan-European market and network model from Pöyry which will enable us to run European demand and generation scenarios in a similar way to those run for GB with dispatch based on relative SRMCs.

- Further work should be carried out on the methodologies to select a single de-rating factor for each interconnected system **(Recommendation 14)** and in choosing these factors DECC should err on the high side **(Recommendation 15):**

  Our report provides advice to DECC on the range of potential de-rating factors that could be used for each interconnected country. This analysis is based on work from a range of consultants as well our own analysis of weather and the benefits from connected systems. However, due to a perceived conflict of interest with our Business Development subsidiary that owns and operates interconnectors it was determined to be inappropriate for us to recommend any de-rating factors for any individual existing or proposed interconnectors. With regard to the ranges we provide for interconnected systems and countries we have taken on board these comments when developing the higher end of the range for this year's report.

  Consequently, DECC with the support of the PTE undertook the analysis to produce each interconnector de-rating factor last year, with input from us when requested. This means we are unable to comment on how these recommendations will be addressed this year but are happy to support DECC in their analysis.

- One recommendation from their 2014 report **(Recommendation 2)** which the PTE felt hadn't been fully addressed last year related to the use of the relative likelihood of scenarios and sensitivities used within the LWR decision tool. In particular they referred to the inclusion of the extreme weather events sensitivities.

  As part of last year's analysis we undertook a series of stress tests of the LWR approach that considered various levels of probabilities or weightings being applied to different sensitivities. All scenarios and sensitivities that were included had to be credible and based on real examples, as with this year's methodology. Notwithstanding the imprecise nature of assigning probabilities to most scenarios and sensitivities, the analysis found that to change the outcome of the LWR required very low probabilities to be used which meant they would need to be non-credible sensitivities and therefore wouldn't have been included anyway. Academic analysis from our academics from Durham University and Heriot Watt University (Zachary, Wilson & Dent) supported this conclusion; however, this work also suggested considering as part of any future development work the potential use of a Bayesian approach[14]. Consequently, we will investigate this as a development project for next year's analysis.

  To provide some practical insight to the potential application of assigning probabilities to sensitivities a recent example highlights the difficulty

[14] Bayesian analysis is a statistical procedure which endeavours to estimate parameters of an underlying distribution based on an assessment of the observed relative likelihoods.

associated with such an exercise. When we were carrying out analysis on the capacity to procure through the Contingency Balancing Reserve products for 2016/17 we incorporated coal closure sensitivities up to 2.8GW within the LWR tool (similar to the non-delivery sensitivities used in this report). At the time it was suggested that we should assign probabilities but it was decided against it given the challenging economic climate for coal stations and feedback from the station operators. This proved to be the correct action because within a short time of that analysis two coal stations announced closure in line with that sensitivity. This reinforces the arbitrary nature of assigning probabilities or weightings to credible sensitivities as they can in a very short timeframe be proved incorrect.

With regard to the inclusion of the extreme weather sensitivities which, in theory, can be apportioned a probability; firstly, we have addressed the PTE's concerns over their inclusion in our analysis in the response to the second bullet above and secondly, their position within the previous ECR's range of potential capacity requirements prevents them from affecting the outcome as the sensitivities at the ends of the range determine the outcome of any LWR calculation. Consequently, while providing important information that enables non-statisticians to assess risk unless these sensitivities are at the end of the potential range of credible outcomes they don't affect the recommended capacity to secure.

In conclusion National Grid is confident it has addressed, where possible, all the PTE's concerns within the approach being used for the 2016 ECR.

2.6 Modelling Enhancements since Last Report

Section 2.5 describes a number of development projects carried out in response to the PTE's 2015 final report. In addition to these projects we have, in consultation with DECC, carried out or commissioned a number of modelling development projects to inform and improve the process. These projects include a review of the LWR methodology, research on the non-linear nature of LOLE, enhancements to the DDM, an update to the interconnector modelling analysis, the calculation of an offshore power curve and updated analysis to assess the relationship between wind generation and demand at times of cold weather.

Following the completion of these development projects, a number of recommended changes were agreed with DECC and the PTE and incorporated into this year's ECR modelling. These recommendations can be split into three categories:

- Data input assumptions
- Modelling changes
- Interpretation of LWR results

2.6.1 Data Input Assumptions

The main enhancements to the input data used by the DDM relate to the inclusion of a separate wind stream for offshore wind derived from a new offshore wind power curve, enhancements to the modelling of interconnector distributions and a wider range of credible sensitivities as described below.

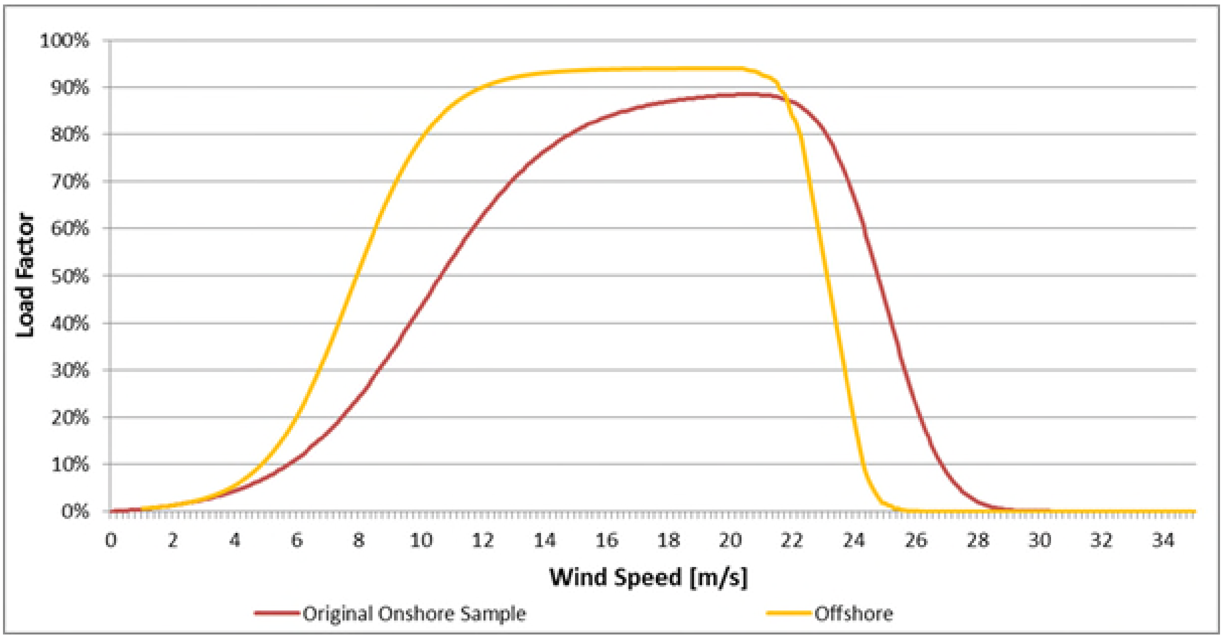
Offshore Wind Power Curve

Previously the DDM used a single wind stream (time series of historic hourly wind load factors) derived from an onshore wind power curve as there was no reliable data available to derive a separate offshore wind turbine power curve.

For this year's process we have sought to gain more accuracy in our modelling of wind, by deriving a separate offshore wind turbine power curve based on robust data from three fully commissioned offshore wind farms over winter 2014/15 (November to March) with turbines below 4 MW in size. When the analysis was carried out, offshore wind farms with turbines of this size comprised the majority of offshore wind capacity. Although the data was limited to three sites, it represented over 300 turbines and the results were consistent enough and sufficiently different from the current onshore wind power curve for us to implement the offshore power curve.

The chart below compares the current onshore power curve against the new offshore wind power curve.

Figure 5: Estimated onshore and offshore wind power curves



Note that these power curves differ from manufacturer's power curves as they include some outages over the winter period and they are based on average half-hourly wind speeds rather than instantaneous wind speeds.

The impact of including separate offshore and onshore wind streams is to increase the contribution from wind generation at times of peak demand as more offshore wind capacity is commissioned.

We will continue to review the data available in future years' analyses and may develop offshore power curves for different, potentially larger sized turbines if sufficient robust data is available and the curves have distinct shapes.

Enhanced interconnector modelling

Baringa has updated and enhanced its interconnector modelling for this year's ECR (see section 4.3 for more details). This analysis was used to create probabilistic interconnector distributions for each country used in the 2017/18 and 2020/21 model runs. For the 2018/19 runs, where interconnectors have been excluded from the Capacity Market, we have assumed a static peak flow that is consistent with the de-rating factors used in 2019/20 and a range of sensitivities similar to those used in the Contingency Balancing Reserve (CBR) analysis.

A wider range of credible sensitivities

Academic work on LWR highlighted that effort should be concentrated on the sensitivities at the extreme ends of the range as these largely drive the outcome from the LWR calculation tool. In consultation with DECC and the PTE we have expanded the range of credible sensitivities modelled in this year's ECR to give a range for 2017/18 that is similar to those used in the CBR analysis (see Chapter 3 for further details on the sensitivities modelled)

2.6.2 Modelling Changes

The main enhancements to the modelling relates to the DDM upgrades and analysis and improvements in the modelling of the relationship between wind generation and demand at times of cold weather.

DDM Upgrades and Analysis

National Grid commissioned Lane, Clark & Peacock (LCP) to carry out upgrades to the DDM and to carry out analysis on some of its outputs.

One key DDM upgrade focused on the modelling of T-1 auctions. Previously the DDM simulated the (T-4) CM auction to secure the capacity required for each delivery year. This upgrade extended the functionality for years where the results of a T-4 auction are known, whereby simulating the T-1 auction secures any additional capacity required above the contracted capacity assumed in the modelling. For this upgrade the DDM calculates the previously contracted capacity using the modelled capacity of contracted plants assumed to be operational – this may be different from the actual contracted capacity awarded in the T-4 auction e.g. if the plant was assumed to close in the scenario modelled or if the modelled capacity value (based on Transmission Entry Capacity (TEC)) is different to the connection capacity declared in the T-4 auction.

Another key upgrade provided functionality to allow for a variable level of correlation between wind output and demand to be modelled in line with the recommendation from academic research (see Chapter 3). In addition some outputs were added to improve the reporting of de-rated capacity and to enable the impacts of capacity changes on LOLE and EEU to be assessed without rerunning the model.

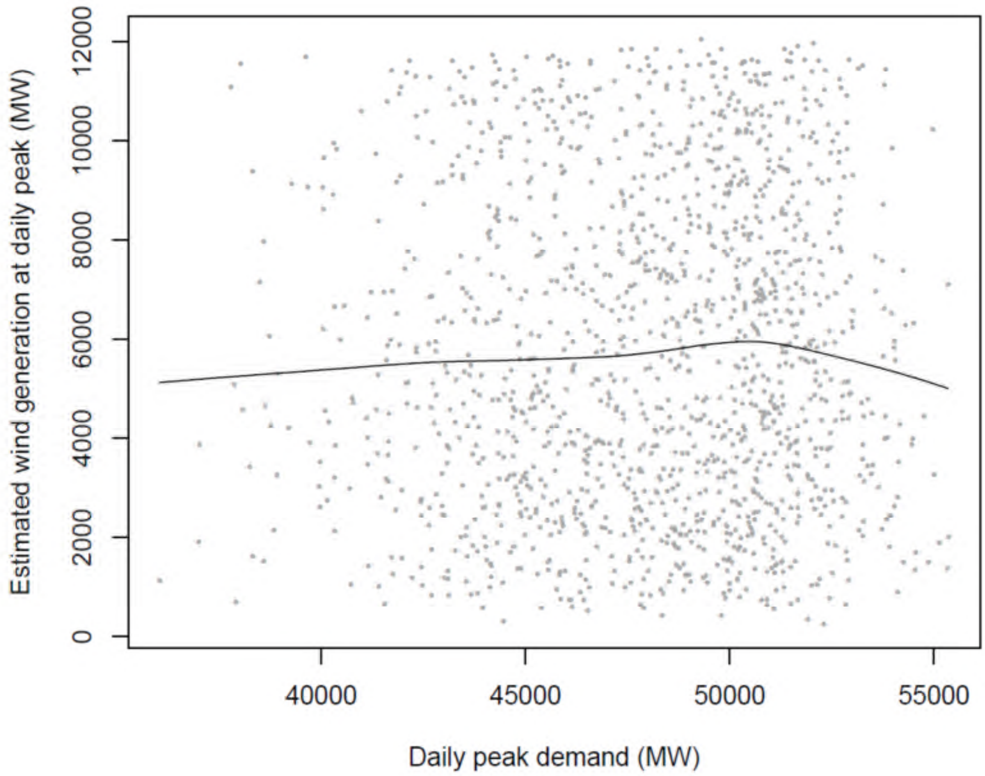
LCP also carried out analysis that confirmed that the DDM and National Grid's own probabilistic capacity adequacy model (used to determine the requirement for CBR) will produce consistent metrics (e.g. LOLE) when given exactly the same (transmission level) inputs. In addition, the analysis showed there was a small difference in LOLE when modelling at a GB end-consumer level (as per the analysis carried out for the Electricity Capacity Report) compared to a transmission level (as per the CBR analysis), but these differences were within the 95% confidence interval of the LOLE calculation.

Note that in our modelling, we did not include attempt to quantify any whole system costs impacts as these do not directly determine the de-rated capacity required to meet the Reliability Standard.

Relationship between Wind Generation and Demand

In previous years, our base assumption in the modelling for the ECR was that wind generation was independent of demand. In 2015 we commissioned Durham University and Heriot Watt University to carry out research using models based on temperature as a proxy for demand to give a sufficiently long demand history. This provided evidence of reduced wind generation at high demands (highest 5 percentile periods) as illustrated in the following chart. To cover this possibility, we modelled a sensitivity with lower wind output at high demand by decreasing the capacity across all onshore and offshore wind farms to give a similar reduction in wind contribution at peak to that shown by the trend line in the chart. For 2019/20, this resulted in an increase of ~0.8 GW in the capacity required to meet 3 hours LOLE (see page 50 of the 2015 ECR).

Figure 6: Illustrative wind generation against daily peak demand scatterplot



Source: Zachary and Wilson

In 2016 we commissioned academics from Durham University and Heriot Watt University (Zachary, Wilson & Dent) to carry out some further analysis utilising Extreme Value Theory (EVT) to recommend how the wind output should be scaled at times of high demand. Extreme Value Theory is the best approach for this type of issue as it makes no prior assumption about the relationships. The scope of this work was shaped by discussions with the PTE and the recommendations were accepted and agreed by the PTE.

This analysis was based on the last 10 years of winter (Nov-Mar) data as that is all the paired wind and demand data that is available. The EVT analysis shows that wind output does fall at times of high demand as shown by an increase in the LOLE compared to the assumption of independence. The EVT approach modelled years individually and averaged the results from the individual years whereas the previous methodology used pooled (10 year) demand and (36 year) wind data[15].

The longer-term recommendation of the research was to consider modelling each year separately, but that is not currently possible within DDM and would require a development project for implementation in 2017 or later. However, functionality does now exist within DDM to use a scaling factor to reduce the wind output at times of high daily peak demand to give results consistent with the EVT approach (see Chapter 3). For the 2016 ECR, the research recommended scaling wind output based on a 10 years pooled (Nov-Mar) wind history to give LOLE figures equivalent to the EVT approach. This results in a scaling of 0.9 (i.e. wind output is reduced linearly from 100% to 90% for daily peak demands between the thresholds of 92% and 102% of ACS peak demand).

The research also suggested that a range for wind output at times of peak demand could be obtained by assuming independence of wind and demand (the previous base assumption) at one end and at the other a higher scaling than used for the base case of 0.8 compared to 0.9. This range formed the basis of the high and low wind sensitivities (See Chapter 3).

2.6.3 Interpretation of Results

Demand is a key element in the decision around the level of capacity to secure in the CM auctions along with the level of non-CM capacity assumed connected in the year in question. To enable the most cost efficient level of capacity to be secured National Grid and Ofgem agreed the DFA Incentive covering demand forecasts that benefits both the consumer and National Grid (similar to the Balancing & Services Incentive Scheme (BSIS) scheme for operating the network)

In agreement with Ofgem, due to the impact of greater uncertainty in the deployment around non-CM eligible generation the decision was made not to develop an incentive around that metric.

The DFA Incentive applies to the demands associated with the scenario or sensitivity that sets the recommendation on the capacity to secure in future capacity auctions. Hence the recommendation needs to be based on a scenario or sensitivity that uses our Base Case (produced specifically for DFA Incentive) and not some other FES scenario demand.

For this reason we have applied the sensitivities to the Base Case (see Chapter 3). We have also modelled a greater number of sensitivities to improve the granularity of potential capacity to secure values so that the gap between values is ideally no more than the confidence interval of the calculation (±400 MW). Note all capacity to secure

[15] Previously 10 years of winter period demand values were pooled to create a single demand distribution and 36 years of winter period wind speeds were used to create a single pooled wind distribution

figures in this report are quoted to the nearest 0.1 GW (100 MW), given the size of the 95% confidence interval as + or – 400 MW.

The model run results from the Base Case and sensitivities along with the four FES scenarios was input into the LWR decision tool which selects a volume (consistent with one of the scenarios or sensitivities) to recommend for the year in question. The most likely outcome, as sensitivities are based around the Base Case i.e. DFA Incentive level of demand, is that the LWR tool selects one of these sensitivities. However, it is still possible the LWR tool could select a FES scenario with a different demand and thus an adjustment would be required e.g. as per Chapter 6 for 2020/21.

Given the inherent uncertainty in the calculation for the capacity requirement for each defined scenario or sensitivity, (as illustrated by a 95% confidence interval) the real answer could be anywhere within that range. Hence any movement away from the LWR output is statistically valid so long as it remains within this range. In the event that the capacity requirement associated with a FES scenario is chosen by the LWR tool then a small adjustment would be required to bring it into line with the DFA Incentive. This would manifest itself as a small movement away from the LWR answer to the nearest sensitivity that was based on the Base Case demands produced specifically for the DFA Incentive. This adjustment would be within the confidence interval i.e. less than ±400 MW and therefore would be statistically permissible. See Chapter 6 for an example of where this adjustment has been used.

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 DECC's Modelling Integrity team to ensure that the QA process closely aligned to DECC'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 assumption/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 process is overseen by the PTE and they review and report on the overall process. Internally the process has governance under Director UK System Operation. National Grid has also worked closely with LCP 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.

3. Scenarios & Sensitivities

3.1 Overview

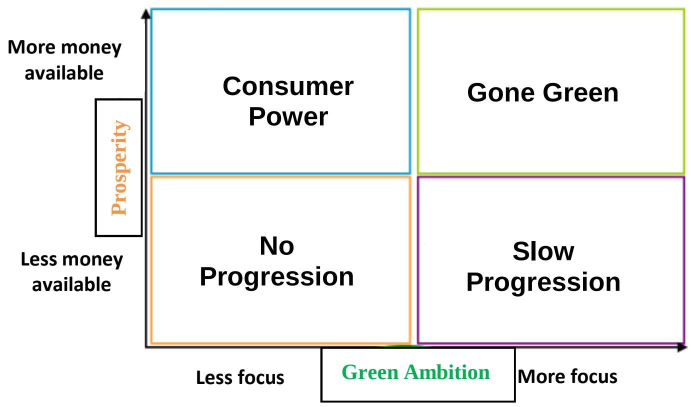
National Grid has a well-established and extensive consultation process on issues related to demand, generation and security of energy supply. This involves a continuous stakeholder consultation process with industry workshops, a summer seminar and bilateral meetings. As part of this process, a range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

- Future Energy Scenarios Stakeholder Engagement
- Future Energy Scenarios National Grid[16]
- 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) reduction announcements in March 2016, 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 2016 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 from 2018/19 onwards, which leaves a 2x2 matrix to create the four scenarios. As such our 2016 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 maintained the names Gone Green, Slow Progression, No Progression and Consumer Power.

Figure 7: 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.

[16] Note that the 2016 document will be published on 5th July 2016

For the purposes of modelling scenarios for the Capacity Market DECC's DDM model has been used, as described in Chapter 2. 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 over time the capacities shown in this analysis may diverge from those in the original FES scenarios.

Base Case

In addition to the four FES scenarios and to be compliant with the new DFA Incentive agreed with Ofgem we have developed a new 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 2020/21 the Base Case then follows the FES scenario that is closest to its DFA Incentive demand level in 2020/21 thereafter, which for the 2016 FES is Slow Progression.

The Base Case assumes some closure or delay in CM contracted plant over the next five years due to, in particular, the challenging economic climate for coal station operators.

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 Gone Green

Gone Green is a world where policy intervention and innovation are both ambitious and effective in reducing greenhouse gas emissions. The focus on long-term environmental goals, high level of prosperity and advanced European harmonisation ensure that the 2050 carbon reduction target is achieved.

Demand

Policy and innovation is focused on energy efficiency across the residential, industrial and commercial sectors, due to greater political certainty over Green Ambitions. Non-binding policies such as EU's 2030 Climate & Energy Framework, which seeks an appliance energy saving of 30%, are adopted. From 2020 carbon reduction policy focuses more on the electrification of heating across all the three sectors. Technological innovation and a high level of prosperity leads to a high take up of electric vehicles. These all combine to initially reduce demand in the short term and then to increase demand from the mid 2020s.

Generation

There is advanced innovation in green technologies with particular emphasis on renewable generation. Sources of renewable generation include solar PV, wind and marine. The sustained focus on environmental targets and favourable economic conditions, ensures continued support for the deployment of renewable and low carbon technologies with significant levels of Carbon Capture and Storage (CCS), renewable generation and nuclear into the future. EU aspirations regarding interconnector capacity for each Member State remain applicable.

3.2.2 Slow Progression

Slow Progression is a world where economic conditions limit society's ability to transition as quickly as desired to a renewable, low carbon world. Choices for residential consumers and businesses are restricted, yet a range of new technologies and policies do develop. This results in some progress towards decarbonisation but at a slower pace than society would like.

Demand

Policy is focused on energy efficiency, due to greater political certainty over levels of Green Ambition but efforts are constrained due to less prosperity, as such the EU's 2030 Climate & Energy Framework is less ambitious. Lower economic growth further hastens industrial demand decline. Both commercial demand and residential demand slowly increase due to an increasing population and slower uptake of energy efficiency measures. These all combine to leave demand remaining flat until around 2030 after which there is a slight increase and demand returns to today's level, by 2040.

Generation

The sustainability agenda ensures that the generation landscape is dominated by renewable technology. Ambition for innovation is constrained by financial limitations, which, in comparison to Gone Green, leads to a slower uptake of renewables.

3.2.3 No Progression

No Progression is a world where business as usual activities prevail. Society is focused on the short term, concentrating on security of supply and affordability above green ambition. Traditional sources of gas and electricity dominate the supply market and there is little innovation altering how energy is used.

Demand

There is less political focus on energy efficiency due to political uncertainty over levels of Green Ambition. Lower economic growth hastens industrial demand decline. Commercial demand slowly declines, as the relative cost of energy favours gas over electric heating. Residential demand slowly increases due to an increasing population and slower uptake of energy efficiency measures. These all combine to leave peak demand remaining flat until the early 2030's after which there is a slow rise as the residential demand picks up.

Generation

There is less money available for innovation and so there are only incremental improvements in existing technology. Gas and existing coal feature in the generation mix over renewables and nuclear, with focus being on the cheapest sources of energy. The lack of focus on the green agenda and limited financial support available for low carbon technologies results in a limited new build programme for nuclear and minimal deployment of less established technology e.g. CCS and marine.

3.2.4 Consumer Power

Consumer Power is a market-driven world, with limited government intervention. High levels of prosperity allow for high investment and innovation. New technologies are prevalent and focus on the desires of consumers over and above reducing greenhouse gas emissions.

Demand

Higher economic growth leads to increasing levels of innovation across the sectors, in particular being driven by consumers in the residential sector, including a strong uptake of electric vehicles. Policy is focused on energy efficiency, but efforts are constrained by political uncertainty over levels of Green Ambition. Industry continues to decline over the period. Commercial demand declines, as the relative cost of energy favours gas over electric heating, but it flattens off in the mid-2020s. These all combine to increase demand over the period

Generation

The favourable economic conditions encourage development of generation at all levels. There is high renewable generation at a local level and high volumes of nuclear and gas generation at a national level. There is minimal deployment of new low carbon technologies, with these technologies not achieving commercial scale operation e.g. CCS and marine.

3.3 Demand Forecast until 2020/21

The demand forecast until 2020/21 has been created for the five year period 2016/17 to 2020/21. 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.

Figure 8 Peak Demand: FES Scenarios and Base Case to 2020/21

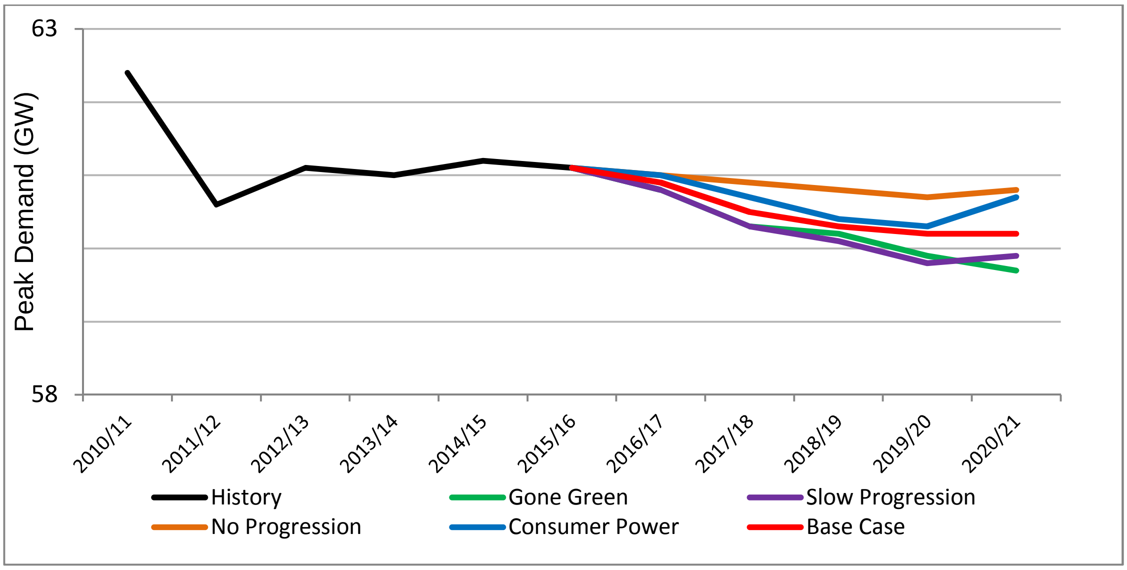


Table 5: Peak Demand to 2020/21

Peak Demand GW	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Gone Green	61.1	60.8	60.3	60.2	59.9	59.7
Slow Progression	61.1	60.8	60.3	60.1	59.8	59.9
No Progression	61.1	61.0	60.9	60.8	60.7	60.8
Consumer Power	61.1	61.0	60.7	60.4	60.3	60.7
Base Case	61.1	60.9	60.5	60.3	60.2	60.2

There is a minimal decline brought about by the continued reduction of demand in the industrial and commercial sectors. This is partially offset by an increase of demand in the residential sector as household numbers increase over the period. This forecast continues a trend that has been evident since 2010/11.

3.4 Demand Forecast 2021/22 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.

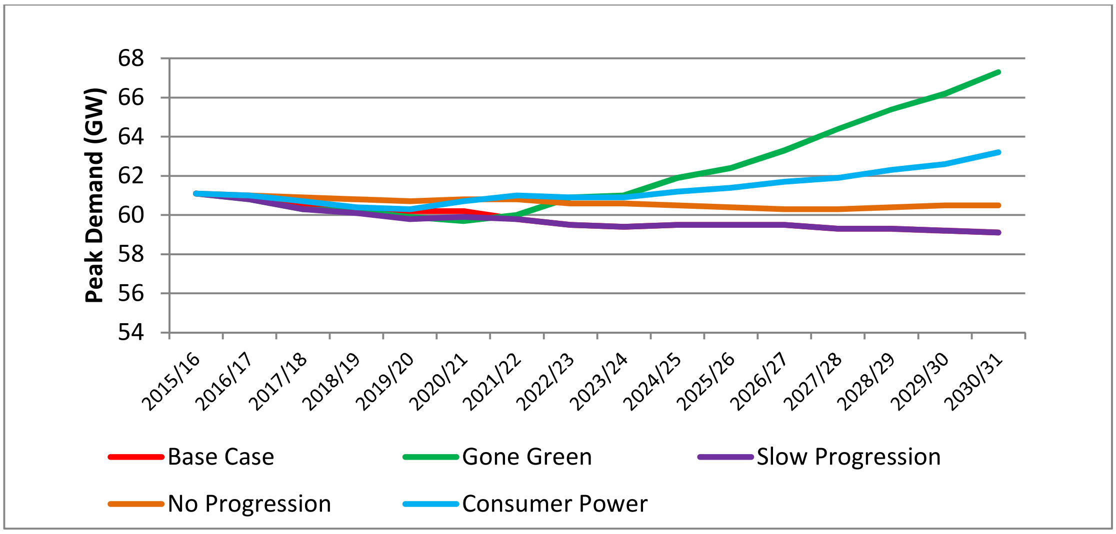
Each of the FES scenarios has its own peak demand projection; again, these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios. The definition of peak demand used in the modelling is Unrestricted GB National Demand[17] plus demand supplied by distributed generation. Reserve required to cover for the single largest infeed loss is not included in the demand definition but is included in the modelling.

[17] 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/

Demand is based on the Average Cold Spell[18] (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 demand side response greater than 2 MW are eligible for the Capacity Market. This can include demand side response through the use of an aggregation service. Note that this includes demand side response at times of Triad charging periods. Therefore unrestricted peak demand is modelled i.e. no demand side response or Triad avoidance has been subtracted.

See the Annex for details on the demand assumptions used in the FES scenarios and section 3.5.8 for more details on demand side response. The following chart shows the peak demands (unrestricted end consumer demand plus losses but excluding exports and station demand).

Figure 9 Peak Demand: FES and Base Case to 2030/31



3.5 Demand Methodology

The demand projections are developed utilising data collected via the FES consultation process as well as in-house analysis. Annual demands can be considered with the following breakdown:

- Domestic
- Industrial
- Commercial
- Other/Sundry

[18] 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.

3.5.1 Domestic

National Grid creates domestic demand by using a bottom up method. This looks at the breakdown of the components of domestic demand. These components are listed below and each is projected individually which, when aggregated, form domestic demand for each scenario.

- Appliances – a regression trend method flexed by the application of primary assumptions and appliance number caps.
- Resistive heat – a new methodology has been applied with the use of modelling by Delta-ee. This produces a relatively gentle increase in demand consistent with the growth in the number of new houses.
- Resistive hot water – The current hot water electrical heat demand comes from published statistics. Due to the projected reduction in heat pumps we expect the power demand for hot water to rise in line with the increase in the housing stock.
- Lighting – regression analysis to determine numbers and consumption by bulb type. This is flexed between scenarios by applying different future take up rates based on the assumptions and possible further policy intervention.
- Domestic annual demand reduction (smart effect) – deterministic modelling using a smart meter roll out profile, project outcome data, such as the Customer-Led Network Revolution[19], and perceived customer engagement rates. This percentage is applied to the underlying domestic demand.
- Heat pumps – using data from a bespoke Delta-ee model the assumption is now that heat pumps, because of their associated infrastructural changes to domestic heating systems, will not be as prevalent as previously thought, except in the Gone Green scenario. Energy efficiency improvements are assumed annually based on manufacturer engagement feedback.
- 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.

3.5.2 Industrial

Industrial demand scenarios are created using a new model developed by Arup, in conjunction with Oxford Economics and National Grid. It is a modular model with three basic components; the first being a macro-economic module which is a forecasting tool that generates long run forecasts for economic activity by sector, the second is an energy demand module which is a modelling tool which projects the sector energy demand based on measures of economic activity, prices and temperature and the third is an energy technology module which is a bottom up technology investment simulation tool. This model is run four times, once for each scenario, with the relevant scenario assumptions entered as inputs to give the required outputs.

3.5.3 Commercial

The same new approach as in the industrial sector has been adopted this year, where the model is utilised to simulate the commercial sector.

[19] http://www.networkrevolution.co.uk/

3.5.4 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.

3.5.5 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 is added. For example, demand side response, electric vehicle charging or heat pump demand at times of peak demand on the transmission system.
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.
- Heat pumps – using 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 in order to determine the electrical heat demand at peak.
- Micro-generation – using the projection capacities by type and a peak load factor assumption, an assessment on the micro-generation levels 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.
- 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.

3.5.6 Calibration

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

3.5.7 Results

The results of the described methods provided are shown below in Annex. For a more detailed description of the FES scenarios please refer the FES document[20]; however, note that the demand is defined differently in the FES document to that shown below which is unrestricted end consumer demand plus losses excluding exports and station demand.

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

3.5.8 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.

The magnitude of the DSR will be dependent on what the market place offers and where the most value can be realised. As yet there is uncertainty as to what form these value streams will take.

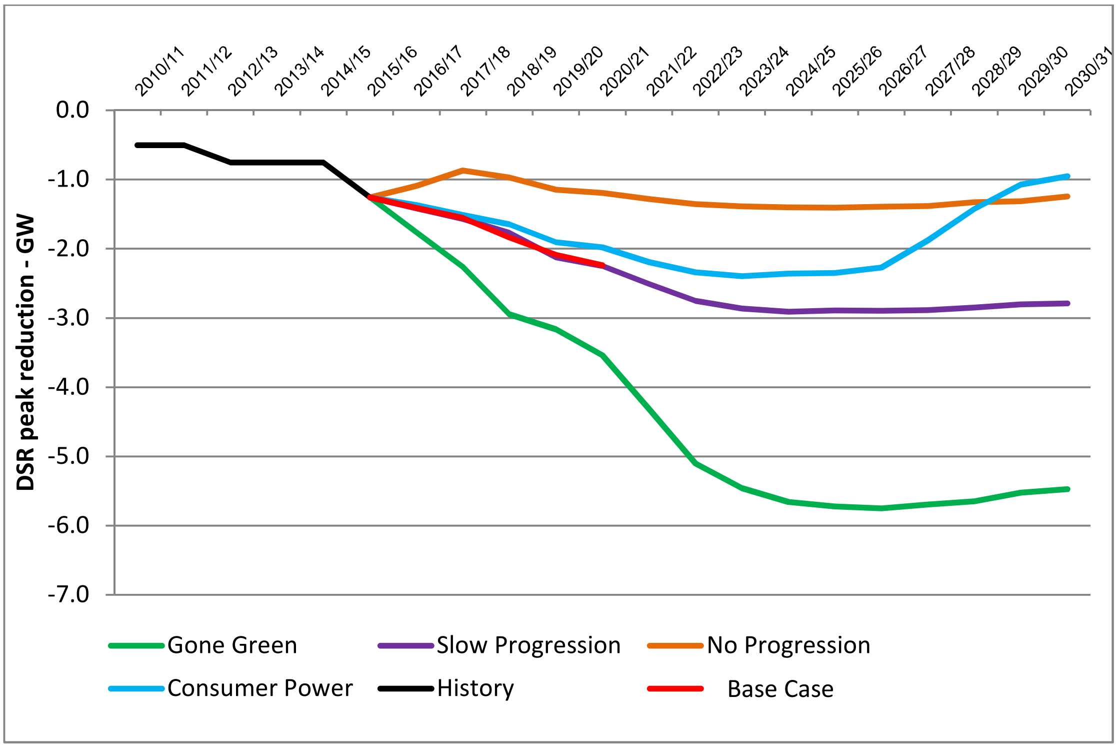
Modification to the Balancing and Settlement Code will require certain businesses to be settled half hourly which should introduce a driver for businesses to use less power at peak, as power prices should be at their highest.

From winter 2017/18 those DSR providers which have an agreement under the capacity market will be available and, it is assumed, they will remain in place thereafter. In the same year, we believe that DSR under Short Term Operating Reserve (STOR) will be available to the Capacity Market, where they will be able to access additional revenues. Thereafter new markets and revenue streams will open up, as a result of this changing environment, with profiles trending downwards towards their maximum reduction values, which they all achieve by 2030. The rate of change depends upon the scenario's conditions.

For the Gone Green scenario, a higher technical uptake rate and a higher utilisation rate of DSR is assumed. This is because the price of electricity will be high, there will be greater peak demand and hence there will be relatively larger savings to be made. There will also be a greener ambition to encourage such behaviour changes. Batteries, in the latter half of the period, will pull down the requirement for true DSR as we view batteries as a form of generation when they are discharging. In No Progression the cost of power will be lower and so the savings will be much less; consequently, a lower figure is assumed. For Slow Progression and Consumer Power mid-ranges are assumed. However, Consumer Power sees significant increases in battery storage and on-site generation. By the end of the period there is only a residual amount of DSR available.

The projections of the industrial and commercial DSR profile reductions have changed since the last FES publication. Figure 10 illustrates this year's view.

Figure 10: Industrial and Commercial DSR profile reduction to 2030-31



Triad avoidance has been recalibrated both as a result of better data as to the extent of avoidance and also an improved understanding of how it is avoided. It is believed that around 63% of Triad avoidance is true demand shifting the rest is achieved by onsite generation which we do not regard as demand shifting. We believe that true Triad shifting is about 1.3 GW. This starting point is based upon an estimated figure for the amount of Triad avoidance which takes place during the peak period (2 GW). The exact value is unknown as it is the cumulative effect of a number of businesses acting independently of each other and network operators.

We have used trial data from reported projects and analyses to inform the scale of DSR that could be expected in the future. However few, if any, of these analyses were based upon actual trial data over a sufficiently long time period with a large enough data set to be definitive. Because of the paucity of such data we have used high, medium and low values from the reports.

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. The demand will not shift however the power source will. The degree to which this occurs is dependent on the scenario’s storage and generation mix.

Residential installation of smart meters will enable the use of time of use tariffs (TOUT). The rate of installation and the levels of engagement, by the consumer, have been modelled. The information to inform this model has come from a number of Low Carbon Network Innovation funded projects. By 2020/21 only 0.1 GW of residential demand side response is assumed in the Base Case.

2016 FES Outcomes

The range of DSR over the four FES scenarios in 2020/21 is from 1.2 GW to 3.5 GW. The Base Case value is 2.2 GW.

For the purpose of this report (and the Future Energy Scenarios report) we consider DSR to be industrial and commercial demand shifting only. More generally DSR or Customer Demand Management (CDM) can mean any demand reduction seen on the transmission system, in particular from distributed or embedded generation e.g. small diesel generators. When considered with industrial and commercial demand shifting, residential demand reductions (brought about for smart meters and appliances) and behind the meter generation (generation with can only meet on site demand) the potential for all forms DSR is shown in Table 6 below. For more information on distributed and embedded generation see section 3.8.

Table 6: Illustration of Potential Covering All Forms of DSR (GW)

Type	2015/16	2020/21	2030/31
I & C DSR (FES) (GG)	1.4	3.5	5.5
Residential Smart (FES) (GG)	0.0	0.1	1.3
Behind Meter Generation (GG)	0.5	1.0	1.7
Behind -the -meter Sub Total	1.9	4.6	8.5
Thermal (NP)	4.2	6.8	10.0
Renewables (GG)	3.1	3.4	3.9
Storage (CP)	0.0	0.6	4.0
Before-the-meter Sub Total	7.3	10.8	17.9
Total	**9.2**	**15.4**	**26.4**

3.5.9 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 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 700 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 Major Energy Users Council.

The impact we would expect as a result of activity is more interest in, and ultimately greater participation of flexible technologies in energy markets. Some evidence of this happening so far has been the increase in Triad Avoidance participation over the past winter (up to 2GW from around 1GW) and procurement by National Grid of 310MW Demand Turn Up, a new trial service run for the first time this year.

3.6 Generation Capacity until 2020/21

The generation forecast until 2020/21 has been created for the five year period 2016/17 to 2020/21. It supports the DFA Incentive which is instrumental in recommending a capacity to secure. This forecast is based on the latest market intelligence and an economic assessment and provides a view of what the generation mix may look like over the five year period. The outcome is that the Base Case sits within the envelope established by the Future Energy Scenarios; see Figure 11.

Figure 11: FES 2016 Transmission connected nameplate capacity to 2020/21

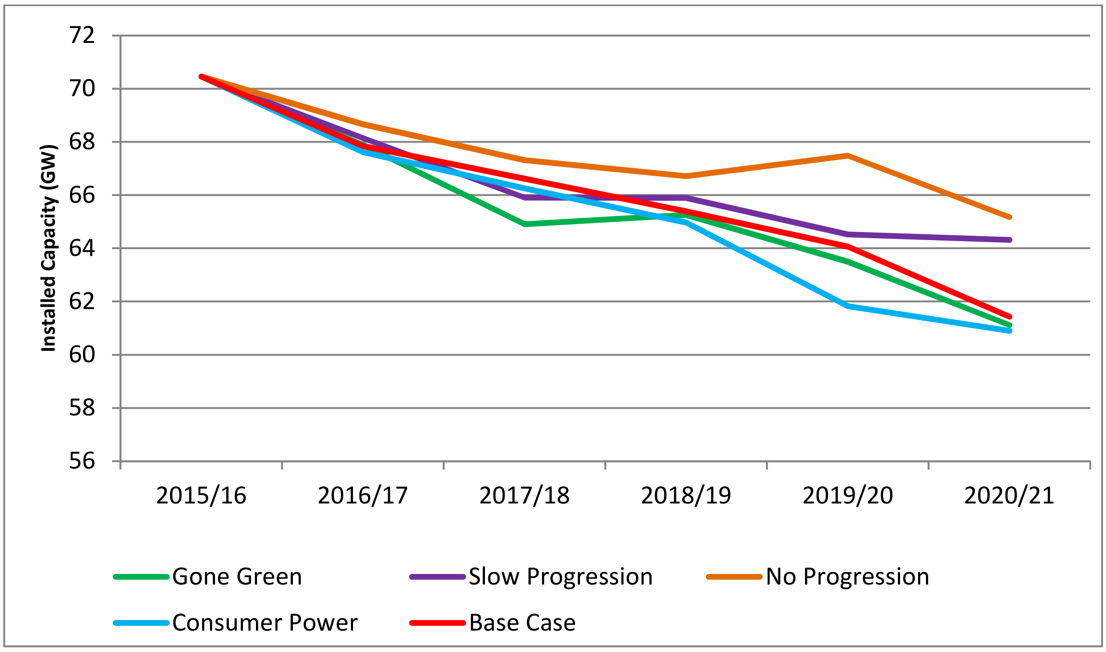


Table 7: Transmission connected nameplate capacity (GW) to 2020/21

Capacity GW	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Gone Green	70.5	67.9	64.9	65.3	63.5	61.1
Slow Progression	70.5	68.1	65.9	65.9	64.5	64.3
No Progression	70.5	68.7	67.3	66.7	67.5	65.2
Consumer Power	70.5	67.6	66.3	65.0	61.8	60.9
Base Case	70.5	67.8	66.6	65.4	64.1	61.4

3.7 Generation Capacity 2021/22 onwards

Each of the FES scenarios has a generation mix that is based on the underlying scenario narrative; this includes the volume of renewable and low carbon capacity along with the Capacity Market eligible plant.

In order to determine the capacity to secure, the various types of generation capacity are split by their eligibility for the Capacity Market. Any generation capacity which is currently receiving, or will receive, support under the following initiatives is not eligible for the Capacity Market:

- Renewables Obligation (RO)
- Contracts for Difference (CfD)
- Final Investment Decision Enabling Regime (FIDeR)
- Feed in Tariffs (FiT)

Once the period in which the capacity is receiving the support has finished, it will become eligible for the Capacity Market.

Any generation capacity that is under a total capacity of 2 MW is assumed to be not eligible for the Capacity Market in this modelling[21]. The unsupported generation capacity that is under 2 MW has been estimated by National Grid to range from 1.6 GW to 2.0 GW in the period to 2020/21 depending on the FES scenario and year. Note that this figure does not include small scale renewable technologies, as these are assumed to receive FiT support and are thus not eligible for entry into the Capacity Market.

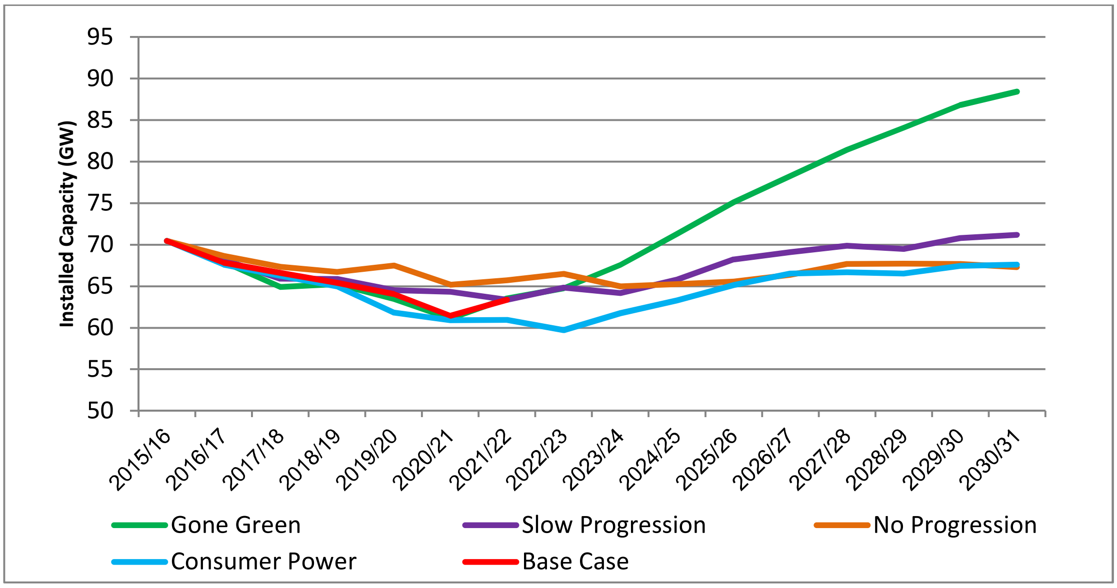
All other forms of generation capacity are eligible for the Capacity Market and it is assumed for modelling purposes that all eligible capacity will enter the Capacity Market. Although capacity is able to opt out of the Capacity Market, it is assumed that no capacity will opt out and remain operational. However, the recommended capacity to secure will be adjusted for known opted out plant following the pre-qualification process.

Any capacity that receives a Capacity Market Agreement for longer than one year, which is either new plant or plant undergoing significant upgrades, will not be eligible for the subsequent auctions while it is under the existing CM Agreements.

The modelling focuses on estimating the total eligible capacity to secure to at least hit the 3 hours LOLE Reliability Standard as the precise mix of generation technologies will be decided by the capacity auction. A breakdown of installed capacity for each FES scenario is shown below:

[21] 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 12 : FES 2016 transmission connected nameplate capacity to 2030/31



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

3.8 Distributed Generation

The scenario projections for generation which is connected to the low voltage networks ('distributed generation') consider what plant is currently operating, potential closures and future openings. The starting point for the assessment comes from a variety of sources such Ofgem Feed In Tariffs register, DECC Planning Base, Grid Code submissions, CM results and other market intelligence. A project list is developed for all existing generation above 1MW in size, this informs the baseline capacity data. The list consists of 30 different existing technologies with the scenarios also considering new type of generation which may connect in the future. The analysis also considers how these technologies contribute to peak demand. The contribution of distributed generation is netted off underlying demand to determine transmission demand. Recent process improvements have assisted in identifying how much distributed generation currently exists. The next area of focus will be improving the data and subsequently analysis on how distributed generation operates throughout the year. This will provide greater understanding as to how small scale generation contributes to demand.

Figure 13: Distributed generation nameplate capacity (excluding Solar) to 2020/21 (GW)

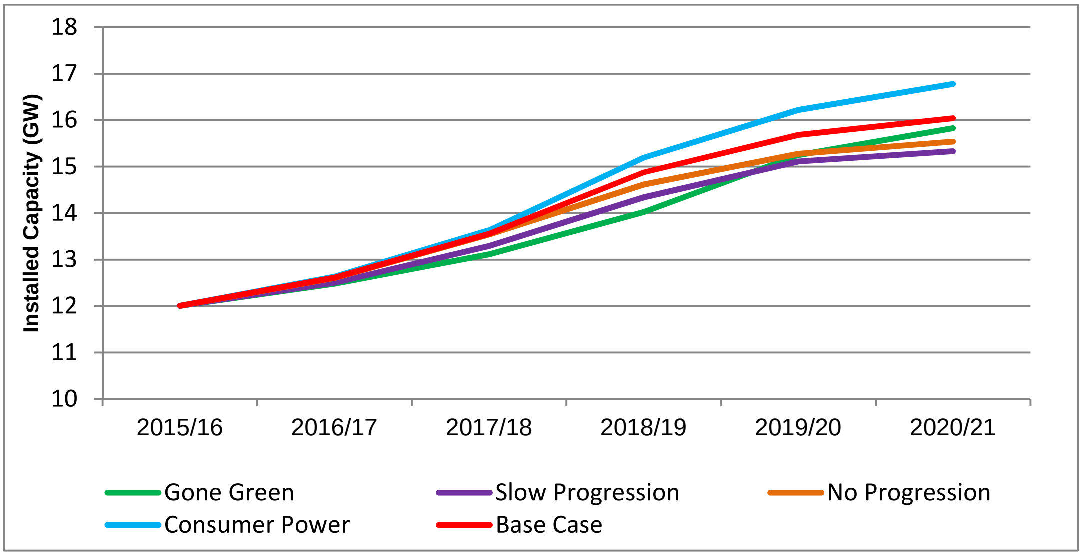
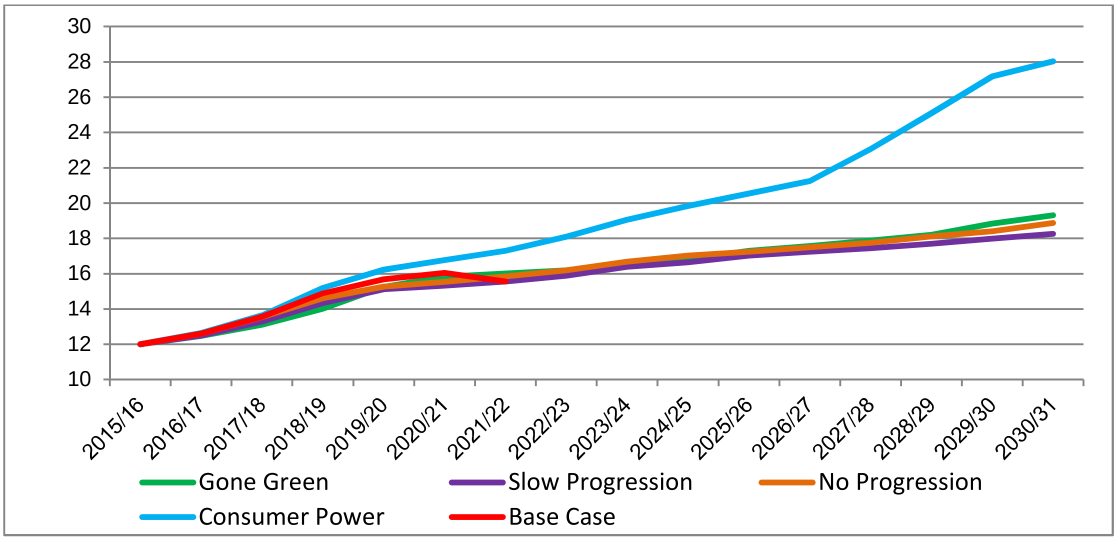


Table 8: Distributed generation nameplate capacity (GW)

Capacity GW	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Gone Green	12.0	12.5	13.1	14.0	15.2	15.8
Slow Progression	12.0	12.5	13.3	14.3	15.1	15.3
No Progression	12.0	12.6	13.5	14.6	15.3	15.5
Consumer Power	12.0	12.6	13.6	15.2	16.2	16.8
Base Case	12.0	12.6	13.6	14.9	15.7	16.0

Figure 14: Distributed Generation (excluding Solar) to 2030/31 (GW)



3.9 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) is 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 will then be placed accordingly within their technology stack.

The placement of a power station will be 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, were also taken into account. The contracted background or Transmission Entry Capacity (TEC) Register[22] 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 about in the very early phases of scoping pre connection agreement are also taken into account.

For power generation connecting to the distributed system alternative sources of data will be used as the starting point for assessment, such as the Ofgem Feed In Tariffs register or DECC Planning Base, as the starting point for the assessment.

The generation backgrounds are then built up to meet the Reliability Standard from 2020/21 onwards.

3.9.1 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 and decreases 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.

3.9.2 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.

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

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 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 spark, dark and clean spreads, electricity wholesale prices and the impact of the carbon price which may impact the operational regime on a technology and/or plant specific basis

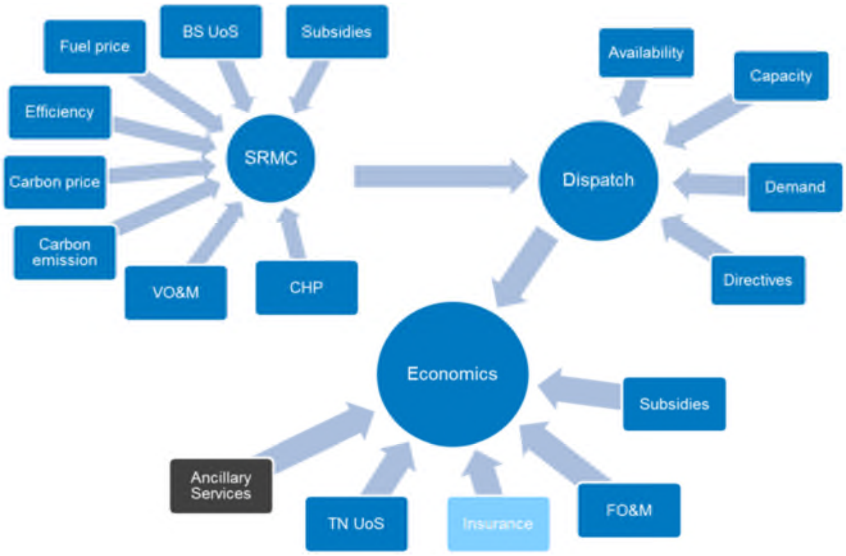
3.9.3 FES Plant Economics

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. The Short Run Marginal Cost (SRMC) of the existing power station fleet has been a focus of the 2016 analysis. The model calculates the SRMC for transmission connected power stations which will be used to inform the power generation backgrounds:

- Computed the SRMCs for each quarter at unit level
- Dispatched according to their SRMCs (low-carbon and CHP set as must-run)
- Profit and loss for each power station is calculated based on its running hours

The results of the analysis inform the transmission generation backgrounds, particularly the plant closures. A high level flow diagram of our process is shown below.

Figure 15: Flow diagram for transmission generation background



NB: The above excludes any revenue for ancillary service. However, within the CM modelling work the DDM makes an allowance for this revenue.

3.9.4 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.

3.9.5 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 European and national level will impact what power supply sources are developed and connected to the NETS. For example, the renewable energy target for 2020 is intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, making it very likely 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 Large Combustion Plant Directive, Industrial Emissions Directive and potentially Medium Combustion Plant Directive. 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.

3.9.6 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered, as explained above. The 2016 power generations backgrounds are developed to both meet demand and to meet the Reliability Standard of 3 hours LOLE. In the years up to 2017/18, the generation backgrounds are driven by more granular intelligence and therefore LOLE can vary quite significantly year to year within this period. If 2016/17 LOLE is predicted to rise above 3 hours then National Grid and Ofgem have agreed to meet the Reliability Standard from procurement of Contingency Balancing Reserve (CBR). From 2017/18 onwards, the backgrounds are developed to not exceed 3 hours LOLE under the Capacity Market (CM).

3.10 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, technological and environmental 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. We have assumed that the cap and floor regime is required for all scenarios other than Consumer Power which is market driven. Additionally, we assumed that only one project between GB and another market can be delivered at any one time under No Progression. For the Base Case we have selected Gone Green for the years to 2020/21 and Slow Progression for the later years.

Table 9: Capacity Levels for Interconnection (in GW)

Capacity GW	2017/18	2018/19	2019/20	2020/21	2025/26	2030/31
Base Case	4.2	4.2	5.2	7.6	13.5	14.9
Gone Green	4.2	4.2	5.2	7.6	19.4	23.3
Slow Progression	4.2	4.2	4.2	4.2	13.5	14.9
No Progression	4.2	4.2	4.2	4.2	9.6	11.0
Consumer Power	4.2	4.2	6.6	8.6	20.1	23.3

The highest electricity interconnector capacities are in the high prosperity scenarios of Gone Green and Consumer Power. The greater regulatory certainty and EU harmonisation within Slow Progression results in more electricity interconnector capacity being built than under No Progression.

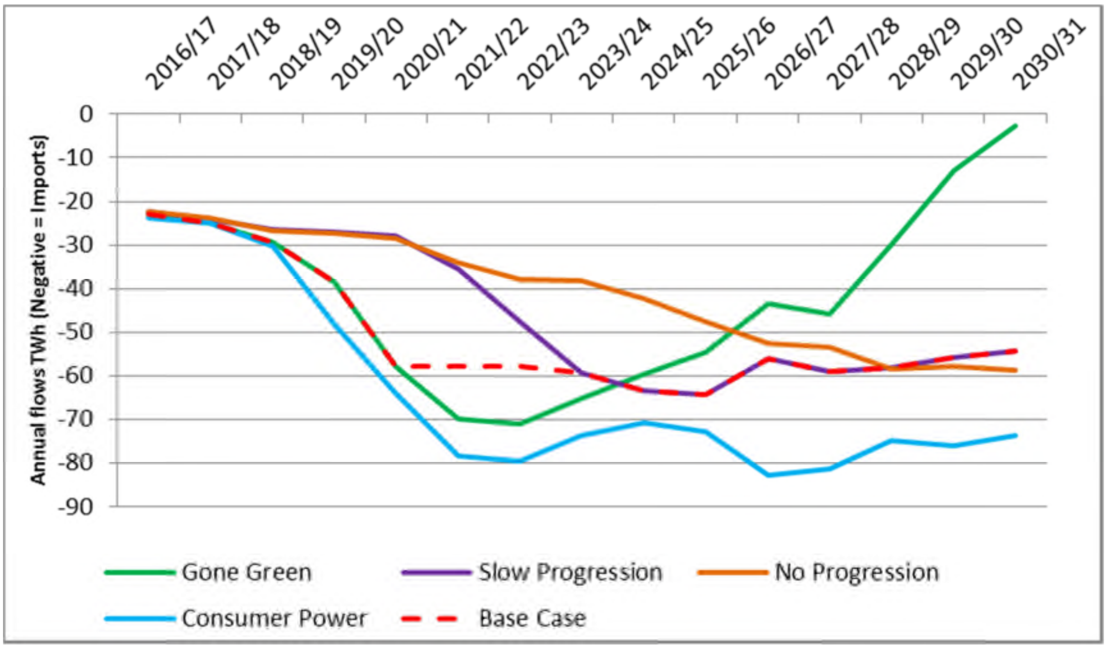
The current GB electricity interconnection nameplate capacity is 4.2 GW. To reach the 2030 levels in Gone Green a further 19.1 GW of additional capacity would be required to be commissioned. Although this is a high delivery profile, it is both consistent with external benchmarking[23,24] and within the supply chain capacity for HVDC projects[25]. This growth is due to the progression of the current cap and floor projects, and the increased certainty for further projects under the second cap and floor window in 2016. The EU has non-binding targets for electricity interconnector capacity. The targets are based upon a percentage of installed electricity production capacity in each country. For GB the targets are: at least 10 per cent by 2020 and 15 per cent by 2030. Both Gone Green and Consumer Power meet the 2030 targets. Although there is a strong pipeline of interconnection projects expected to add at least 7GW of capacity, most of this is expected to be connected in the early 2020s. A more aggressive build programme than envisaged in the scenarios would be required to reach the 2020 target.

In Gone Green, high levels of variable renewable generation encourage market coupling through electricity interconnection. However, the more regulated approach in this scenario leads to small development delays. Consumer Power sees fewer delays as it is market driven with little regulation in place. The main driver in Consumer Power is to gain competitive advantage through the lower costs available in new markets.

The drivers in Consumer Power are seen in both Slow Progression and No Progression, although they are limited by the low level of prosperity. Under lower prosperity conditions the certainty of a regulated approach means there is more capacity in Slow Progression than in the more risk-averse No Progression.

[23] Department of Energy and Climate Change, More interconnection: improving energy security and lowering bills, December 2013, https://www.gov.uk/government/publications/more-interconnection-improving-energy-security-and-lowering-bills
[24] Aurora Energy Research, Dash for Interconnection, October 2015, https://auroraer.com/files/reports/Dash%20for%20interconnection%20-%20Aurora%20Energy%20Research%20-%20February%202016.pdf
[25] ABB, ABB to invest $400 million on expansion of cable production capacity in Sweden, December 2011, http://www.abb.com/cawp/seitp202/47b4bc352349fd3dc125796000480a21.aspx

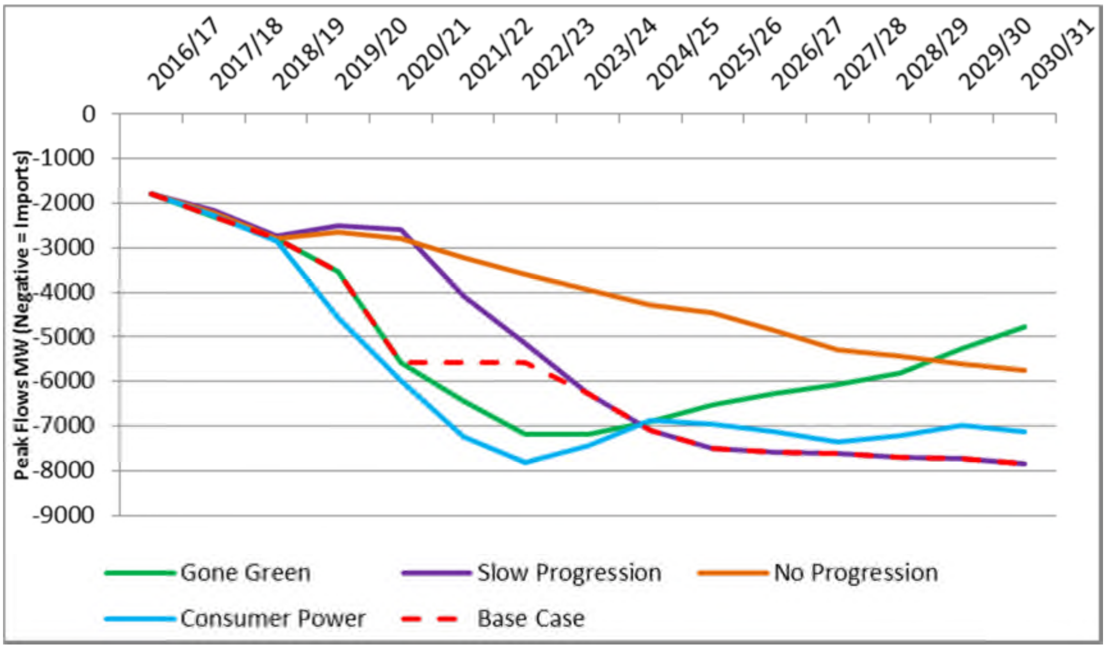
Figure 16: Annual interconnector net flows



As with all interconnector flows, annual flows, shown in

Figure 16, are driven by prices. Until the mid-2020s the carbon floor price encourages cheaper continental generation to be imported into GB across all of the scenarios. Later in the period the increasing proportions of renewable generation and the price coupling effects of electricity interconnection bring the market prices closer together. While this reduces the net annual flows, GB retains a net import position.

Figure 17: Peak interconnector net flows



In FES 2016 we define peak flows, shown in Figure 17, as the flows which could be relied on to supply winter peak demand when Great Britain needs imports. This is a more extreme measure than average flows at ACS (average cold spell) conditions. Actual flows at times of ACS peak demand could differ significantly from these figures due to the impact of other factors such as wind generation and the stress level of connected markets.

We commissioned external consultants (Baringa) to assess the flows between GB and connected countries for each scenario using a pan-European market model. Flows were modelled for each scenario based on FES 2015 demand and generation data, FES 2016 electricity interconnector capacity, and the consultancy's own dataset for non-GB countries.

However, it should be noted that these peak figures aren't used in the CM modelling as that uses probabilistic distributions from Baringa's pan-European market model (except for 2018/19 which uses, as a base assumption, the de-rating factors used in the 2019/20 T-4 auction, set by DECC, applied to the interconnectors – see 3.11.5).

3.11 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. In addition to the FES scenarios, a DECC Scenario has been included for information but hasn't been included in the LWR calculation to ensure the recommendation is fully independent by basing it on and around National Grid's Base Case and four FES scenarios.

While the FES scenarios vary many variables (see list of primary assumptions in Annex 8.2) 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 station peak availabilities, weather, wind, peak demand forecast performance and non-delivery of contracted coal capacity. In addition, for 2018/19 only, there are sensitivities covering a range of interconnector peak flows.

To provide the reference case to which the sensitivities have been applied, a Base Case has been introduced. Up to 2020/21, 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 2021/22 the Base Case takes the demand and generation mix from the Slow Progression 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.

3.11.1 Low Wind (at times of cold weather)

As detailed in Section 2.6.2, recent statistical analysis undertaken by Durham 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 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..

3.11.2 High Wind (at times of cold weather)

As detailed in Section 2.6.2, recent statistical analysis undertaken by Durham 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).

3.11.3 High Plant Availabilities

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 2.3.2). 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 84% to ~89% and for CCGTs by 2% from 90% to 92% in 2020/21 and from 88% to 90% in 2017/18 and 2018/19. These higher availabilities are based on one standard deviation above the mean of observed figures from the last seven years. Coal availabilities haven't been flexed as coal availabilities show very little variance over the last seven years. In addition, other technologies haven't been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their high availability levels.

In 2017/18 for example, adjusting availabilities has an impact on the diversity of 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. In addition to these sensitivities being the statistically correct thing to do, they also have the added advantage of providing greater granularity to the LWR calculation.

3.11.4 Low Plant Availabilities

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 2.3.2). For nuclear the availability reduces from 84% to 80% and for CCGTs from 90% to 88% in 2020/21 and from 88% to 86% in 2017/18 and 2018/19. These lower availabilities are based on one standard deviation below the mean of observed figures from the last seven years.

3.11.5 Interconnector Assumptions & Sensitivities (2018/19 only)

In the 2016 ECR, interconnector capacities are based on the FES scenarios (see section 3.10). For the 2017/18 and 2020/21 model runs the flows are calculated as part of the probabilistic modelling hence there is no requirement for interconnector sensitivities in these years' model runs. However for the 2018/19 analysis interconnectors are modelled using static peak flow level assumptions. A base flow assumption for the scenarios and a range of flow sensitivities around this base 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 participation/treatment of interconnectors in the 2019/20 T-4 auction we used the de-rating factors assigned to the interconnectors in that auction giving a base flow of 1900 MW with range of sensitivities consistent with that used in the Contingency Balancing Reserve (CBR) analysis i.e. continental imports from Europe ranging from 3000MW to 750 MW. However, when we produce our recommendation for 2018/19 T-1 next year we may consider calculating this base flow based on probabilistic approach.

Flows to Ireland were also varied in the sensitivities from an export of 450 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 Continent and Ireland.

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

Assumed Flow (MW)	Continent	Ireland	Net Flow
Base	1850	50	1900
750 Imports	750	-450	300
1500 Imports	1500	-200	1300
2250 Imports	2250	250	2500
3000 Imports	3000	500	3500

3.11.6 Weather – Cold Winter

The cold weather sensitivity addresses the uncertainty of 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 10 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 5 years. If a longer history is assumed (90 years) then such weather conditions are actually closer to the average but due to climate change a 30 year history may be a more suitable basis.

There are two further reasons why this sensitivity is included. Firstly, LOLE is a metric that is highly non-linear and excluding the sensitivity would fail to fully account for the non-linear impact of cold weather on LOLE and therefore understate its impact. This can be easily illustrated by considering two hypothetical scenarios both of which meet the Reliability Standard but have significantly different impacts.

- Over a ten year period this scenario has 3 hours LOLE in each year which gives an average of 3 hours LOLE over the ten year period and therefore meets the Reliability Standard and with mitigating actions could result in no controlled disconnections.
- Over a ten year period this scenario has 30 hours LOLE in one year and 0 hours LOLE in 9 other years which gives an average of 3 hours LOLE over the ten year period and therefore meets the Reliability Standard but this time mitigating actions may not be able to prevent controlled disconnections – hence the impact on consumers is significantly different and demonstrates why LOLE as a first order measure fails to address this risk.

The final reason for including this sensitivity is reputational as this sensitivity is clearly credible given that the winter was less than 6 years ago, wasn't extreme and from a practical communications point it would be extremely difficult to defend a position that didn't consider it in the calculation.

Section 2.5 contains further justification including academic research that supports the inclusion of the cold and warm winter sensitivities in the analysis.

3.11.7 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 recent warm winter 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 15 years.

3.11.8 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 overforecast demand over recent years 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 recently 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 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.

3.11.9 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 FES ACS peak demands.

3.11.10 Non-delivery of Contracted Coal Capacity

Given the poor state of coal station economics, recent coal closure announcements and the recent Government announcements around the future of coal, there is a credible risk that coal stations with CM contracts will close ahead of the delivery year or coal stations opting out of the CM that had previous indicated they would be operational will close. The Future Energy Scenarios already take account of "higher risk non-delivery issues ("known knowns") e.g. plants that have already announced closure or plants assumed to close under the conditions in the scenario framework for particular scenarios.

In addition, the 2016 ECR includes a range of non-delivery sensitivities to cover the credible risk of earlier than expected closures of coal stations assumed to be generating in the FES. For example, stations with existing CM contracts (from the 2018/19 or 2019/20 T-4 auctions) could close early; stations successful in future auctions could close before the delivery year e.g. due to breakdowns being uneconomic to repair; and there is a possibility that all coal stations could close with or without CM contracts.

If these adjustments for non-delivery are made prior to simulating the auctions in the DDM the model will assume a different new or existing plant is contracted instead, resulting in the same de-rated requirement as it is non-technology specific. Hence these non-delivery sensitivities have been modelled by reducing the "outside CM" capacity after the DDM runs.

The non-delivery sensitivities deal with uncertain risks ("known unknowns") for non-delivery and also assist with the granularity in the LWR calculation. A range of non-delivery sensitivities with incremental steps of 400 MW (around the de-rated capacity of a typical coal power station unit) have been modelled up to a maximum of 2800 MW in 2017/18 (similar to the range modelled in the CBR analysis for 20167/17) and 3600 MW in 2018/19 and 2020/21 (roughly equivalent to the de-rated capacity of two 2 GW coal power stations).

3.11.11 Sensitivities Considered but Rejected

A number of alternative sensitivities were considered for inclusion but following discussions with DECC and the PTE were rejected.

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 concept of 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 DECC 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.

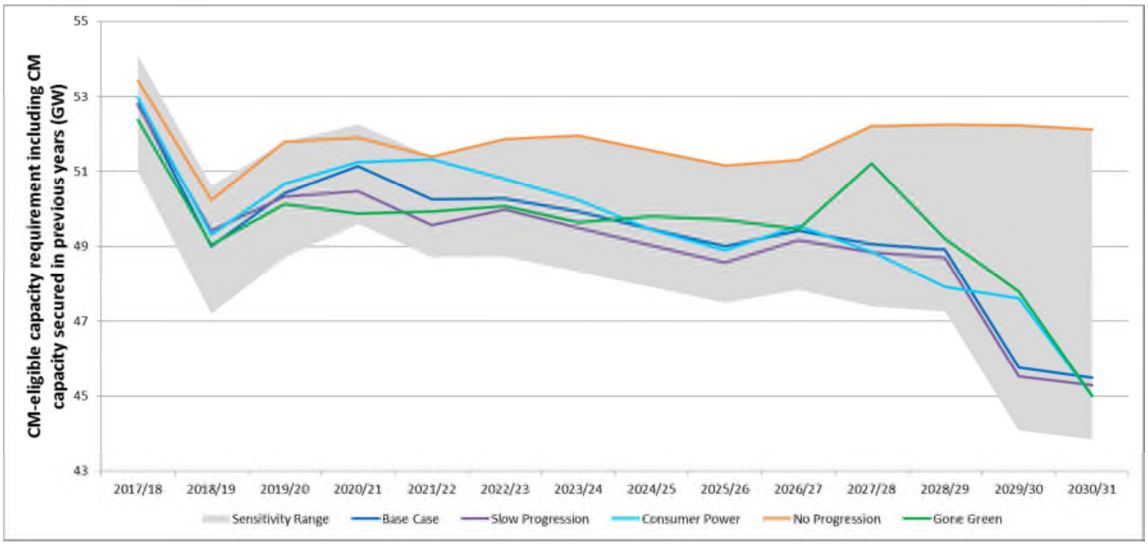
Black Swan Events– These are defined as events that have low probability but high impact. Examples for GB would include large nuclear type faults, extreme weather e.g. Jan. 1986/7, significant technology closures due to economics or policy plus issues not yet identified ("unknown unknowns"). We have 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 outcomes and only changing one variable. Given this and given that economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with DECC and the PTE not to include any "black swan" event sensitivities.

3.12 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 (2017/18, 2018/29 and 2020/21). 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/transitional and T-4 auctions. The requirement for 2017/18 was derived from the 2017/18 model runs (see chapter 6), the requirement in 2018/19 and 2019/20 from the 2018/19 model runs (see Chapter 7) and the capacity requirement from 2020/21 to 2030/31 from the model runs for 2020/21 (See Chapter 5). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 18 shows the range in modelled capacity requirement in future years including any new / refurbished capacity secured in previous years.

Figure 18: 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 sensitivities is the same as the Base Case as the increase in capacity required is offset by the reduction in contracted capacity closing before the target year.

As can be seen in the chart, the No Progression scenario has a relatively stable capacity requirement over the period whilst the remaining three Future Energy Scenarios show a gradual decline over 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). The exception to this is a small increase in 2027/28 for some scenarios 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. 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 year 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 2017/18. Prior to 2017/18 there isn't a similar definition of capacity so any figures would be purely illustrative and therefore potentially misleading. A separate mechanism exists (Contingency Balancing Services[26]) to address any shortfall prior to 2017/18 that has been agreed between National Grid and Ofgem, initially for 2014/15 and 2015/16 and then extended to 2016/17. Although the requirement is calculated following the same principles as laid out in this report, it is nevertheless analysed separately and the requirement is communicated via different means to this report.

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

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 2020/21 by the conventional generation technologies and includes a comparison with those used last year for the 2015 T-4 Capacity Market Auction[27].

Table 11: Conventional Plant De-rating Factors

Name for technology class	Plant Types Included	De-rating factor (2015)	De-rating factor (2016)
Oil-fired steam generators	Conventional steam generators using fuel oil	84.61%	85.44%
OCGT and reciprocating engines (non-autogeneration)	Gas turbines running in open cycle fired mode Reciprocating engines not used for autogeneration	94.54%	94.17%
Nuclear	Nuclear plants generating electricity	82.31%	84.36%
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	84.87%	86.16%
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.	96.63%	96.29%
CCGT	Combined Cycle Gas Turbine plants	89.00% (2019/20)	2017/18 87.60% 2018/19 88.00% 2020/21 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	87.86%	86.92%
DSR		86.80%	86.88%

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

[27] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity_Market_Auction_Guidelines%20Final%20D-15.pdf

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

- The following explains the methodology used to calculate the DSR De-rating figure (using Committed STOR availability over the most recent 3 winters at 50th percentile demand):

  1. <u>The mean average of the declared availabilities</u>:
  - The mean average of the STOR available volume or zero if not available, where the volume is as settled including any deemed unavailability following an Event of Default, for the defined STOR units in the defined settlement periods.
  - Units that have declared themselves unavailable will have zero availability for the relevant period.
  - As per the STOR Standard Contract terms, units that have failed to deliver by the end of their defined response time following a utilisation instruction (<90% of expected volume in response time) will have zero availability for the periods impacted.
  - Units that have delivered <90% expected volume for an instruction will have zero availability for the remainder of the window.
  - Units that have baseline generation/load at level other than agreed i.e. if a generator metering >0MW, if a demand unit, metering < Contracted MW, will have zero availability for the entire window.

  2. <u>Of all Non-BSC Balancing Services</u>: Non-BM Committed STOR units that were contracted for the latest winter season.

3. Over the High Demand Settlement Periods: Settlement Periods inside defined STOR windows between 7 am and 7pm where the GB peak demand for the day was greater than the 50th percentile of demands for that winter (November to March).

4. For the three immediately preceding Core Winter Periods: on week days between December and February.

5. Divided by their contracted volumes: settlement period STOR contract volume.

4.3 Interconnectors

As part of the UK's State aid approval for the Capacity Market, interconnectors have been eligible to participate in the CM since the 2015 auction. As such, the UK has committed to include interconnectors in the 2017/18 early auction. The future of potential flows through interconnectors is very uncertain and as a consequence there is no one 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 DECC, has considered in determining an appropriate de-rating factor range for the Secretary of State to then decide the factors to apply to interconnectors in the 2017/18 early auction and 2020/21 T-4 auction.

4.3.1 Methodology

We commissioned Baringa to model flows between GB and connected countries for each scenario using their pan-European market model. Flows from November to February were modelled for each scenario based on FES 2015 demand and generation data, FES 2016 electricity interconnector capacity, and Baringa's own dataset for non-GB countries. This year's analysis has been enhanced incorporating recommendations from the PTE. The enhancements are:

- Scarcity premia modelled
- Demand history increased to 9 years (2006 to 2014) correlated across Europe and with wind generation
- Larger number of simulations

The modelling assumed that I-SEM would go live in October 2017 removing the incentive for flows from GB to Ireland during the peak winter hours. Ireland was modelled as a single price area so Ireland's North/South constraint had no impact.

All hours with a GB capacity margin less than or equal to zero, from the model simulation, 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 all four scenarios sets the top of the recommended range of de-rating factors. Percentiles of the distribution of these simulations were calculated to assess the variability in flows.

DECC commissioned Pöyry to update their analysis of historical de-rating factors used to inform last year's ranges. In all cases these set the bottom of the recommended range, except for Ireland in 2020/21 when the average of the four scenarios 90th percentile flow was used. This is because we have assumed that the successful introduction of I-SEM could fundamentally change the market meaning that the historical market data may no longer be valid.

Longer term weather, from 1957 to 2014, was analysed to assess whether the simulation results reflected long term weather conditions following the increase from four to nine years data.

A number of subsets of the Baringa modelling results were selected to evaluate how flows were affected by low temperatures and low winds in the connected countries. The four sets of criteria were

- Lowest 1% of temperatures
- Lowest 1% of temperatures and wind speeds less than 5 knots
- Lowest 5% of temperatures
- Lowest 5% of temperatures and wind speeds less than 5 knots

4.3.2 Baringa Pan-European Model Results

The following two tables show the average flow across the four FES scenarios as a percentage of capacity from the Baringa analysis. The 90th and 10th percentile values are the average for the four scenarios.

Table 12: Baringa 2017/18 results – Imports as % of interconnector capacity

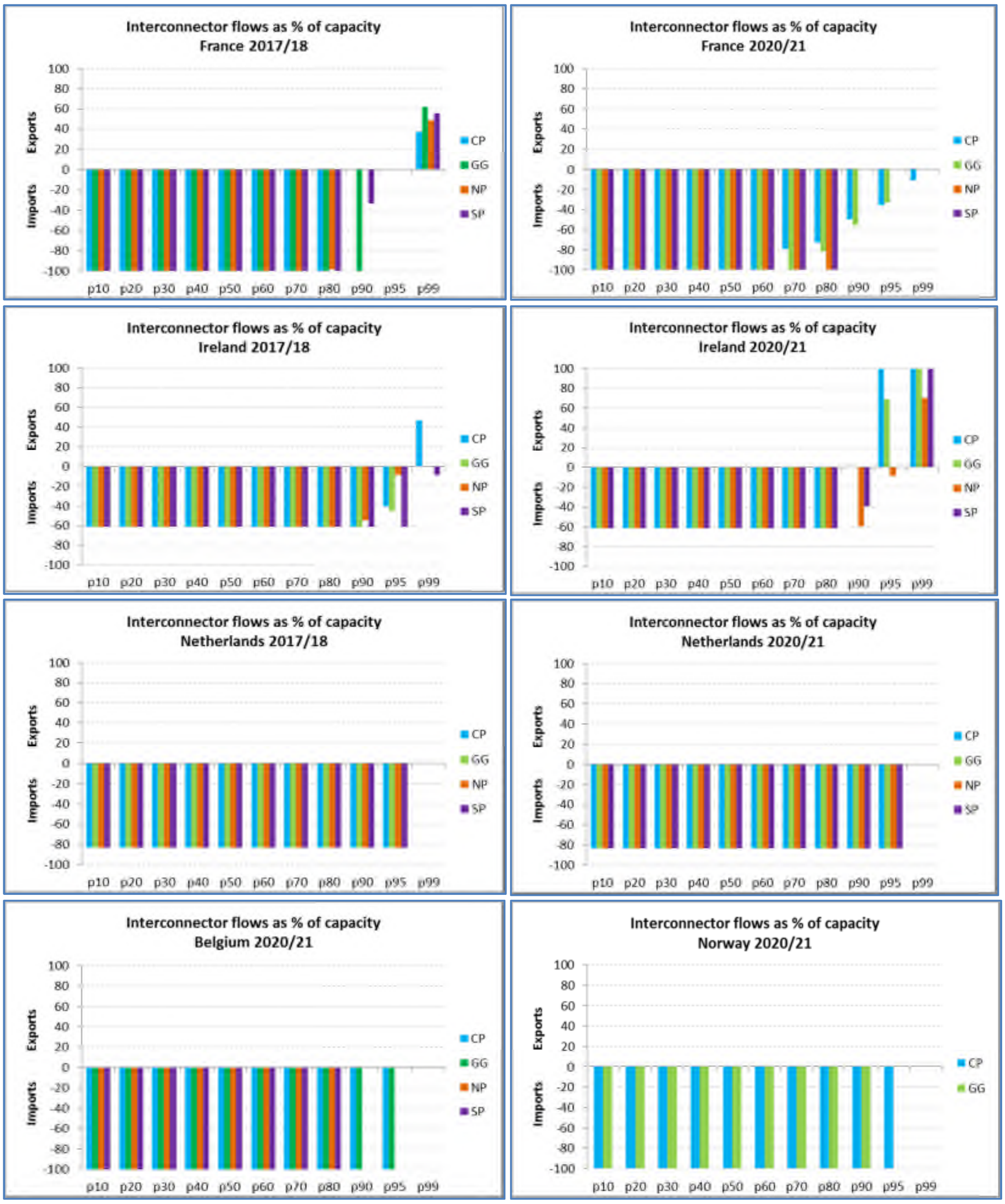
2017/18	France	Netherlands	Ireland
Gone Green	91	81	58
Slow Progression	88	82	59
No Progression	81	81	56
Consumer Power	85	81	57
90th percentile	33	83	60
10th percentile	100	83	61

Table 13: Baringa 2020/21 results – Imports as % of interconnector capacity

2020/21	France	Netherlands	Ireland	Belgium	Norway
Gone Green	89	82	46	97	93
Slow Progression	89	82	53	89	-
No Progression	88	81	56	84	-
Consumer Power	86	82	46	97	98
90th percentile	26	83	25	50	100
10th percentile	100	83	61	100	100

Distributions of flows as a percentage of capacity, see Figure 19 show that whilst some countries such as Norway and the Netherlands have stable imports, others have a number of hours where imports reduce significantly or switch to exports.

Figure 19: Interconnector flow distributions



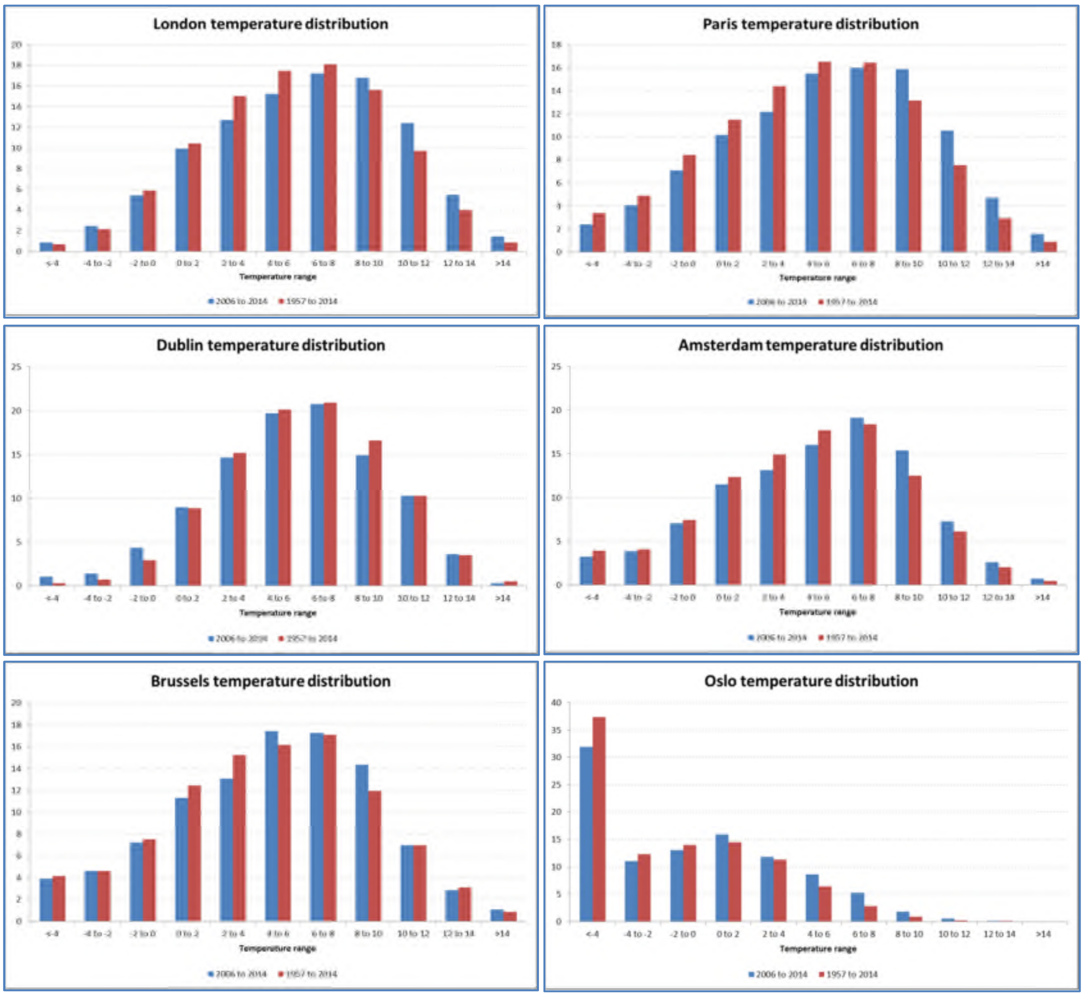
The 10th and 90th percentiles from these distributions are shown in Table 12 and Table 13 with the 10th percentile giving an indication of the highest flow that could be expected. This is 100% of capacity for France, Belgium and Norway. The lower figures for Netherlands and Ireland reflect assumptions made about restrictions on the ability of the interconnectors to deliver full capacity. For the Netherlands the 83% figure is due to the maximum sustainable flow being 1000 MW whilst the capacity of 1200 MW is based on the TEC. This is the maximum capacity for the interconnector but it is assumed it can only be produced for a short period. For Ireland, the flows assume a maximum import into Scotland of 80 MW due to network constraints whilst the capacity of the interconnectors has not been reduced.

The 90th percentile gives an indication of whether flows are maintained in all situations. The Netherlands and Norway continue to flow at high rates whilst France, Ireland and Belgium all show much reduced flows. France is very weather sensitive with a need for large net imports at high demand levels so the availability of imports from France is reduced when stress conditions coincide. As Ireland has a high proportion of wind generation its ability to export to GB depends on stress periods in Ireland, caused by low wind and high demand, not coinciding with GB's need for imports. Belgium is reliant on its nuclear power stations remaining operational.

4.3.3 Validation/ Comparison/Other Analysis

One concern with the analysis in 2015 was that there were only four historical years in the pan-European modelling. This year's analysis increases the number of historical years to nine (2006 to 2014). Comparing the temperature distributions for these nine years with all years from 1957 produces small differences, as illustrated in Figure 20 but when these differences are used to scale the interconnector flows to represent the longer time period the impact on mean flow percentages is minimal so no scaling to long term weather has been applied. Further analysis may identify if there are significant differences in extreme events but this will require a detailed project which cannot be undertaken in time so will be considered as a development project for next year.

Figure 20: Temperature distributions



4.3.4 Pöyry historical analysis

DECC commissioned Pöyry to update their analysis of historical flows. The historical data used was the top 50% of peak demand periods during the winter quarter, 7am to 7pm business days from 2009 to 2015. 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. In recent years interconnector flows have become more consistent with price differentials. The main exception is Ireland where the relationship between flow direction and prices remains poor.

For this analysis two sets of data are shown. The Pöyry report calculates the average for the last seven years. This sets the floor for the de-rating factors. In addition we have also calculated the average of the last four years to reflect changes in the market coupled era. However, the longer period represents a wider range of events and risks rather than just price. Examples of such events include droughts in Norway which are better reflected by the longer period. Figure 21 shows the efficiency of interconnector flows measured as the percentage of time interconnector imports to GB are in line with positive price differentials. Ireland is expected to remain low until the introduction of I-SEM in October 2017. Table 14 compares the historical de-rating factors based on the seven year and four year historical averages.

Figure 21: Efficiency of interconnector flows

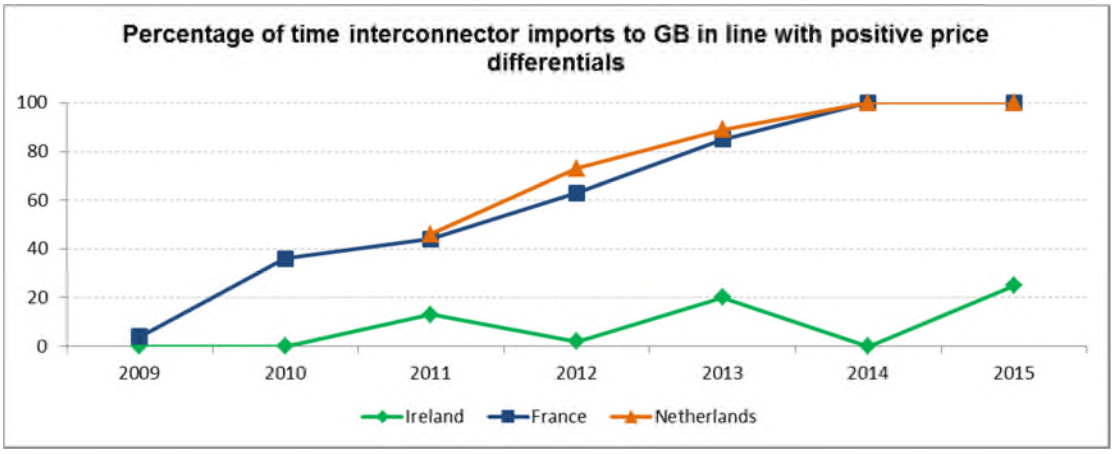


Table 14: Historical de-rating factors

%	France	Netherlands	Ireland	Belgium	Norway
2009-2015	45	70	2	65	76
2012-2015	67	76	4	76	92

4.3.5 Country de-ratings

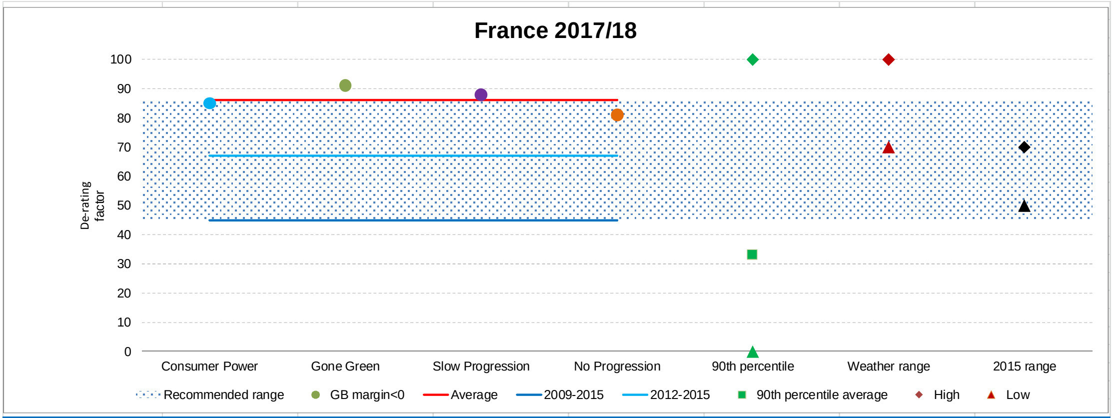
The following graphs show the Baringa results for each scenario, the 90th percentile (for France and Ireland only), Pöyry historical averages, the maximum and minimum from the low temperature and wind period combinations, and the recommended range from 2015. The low temperature and wind periods are for hours where GB capacity margin is less than or equal to zero and the temperatures and wind speeds in the connecting country are low. The percentile figures are provided for Ireland and France only. For these two countries co-incidence of stress events can result in major shifts in the size and direction of flows. The 90th percentile figure gives an indication of the imports that can be relied on 90% of the time imports are required.

As this methodology is based around the modelling of European markets step changes in results could potentially occur between years as the modelling develops. For example, closure of nuclear and coal plants could reduce the times mainland Europe has surplus generation available to export to GB, and lead to lower de-rating factors. Hence any changes from previous years should be smoothed unless there is good evidence to suggest otherwise.

The recommended ranges are produced by selecting the average of the four scenarios for hours where the GB capacity margin is less than or equal to zero for the high value. The low value is selected from the Pöyry history for the last seven years with the exception of Ireland for 2020/21, which is based on the average 90th percentile value from the four scenarios.

France:

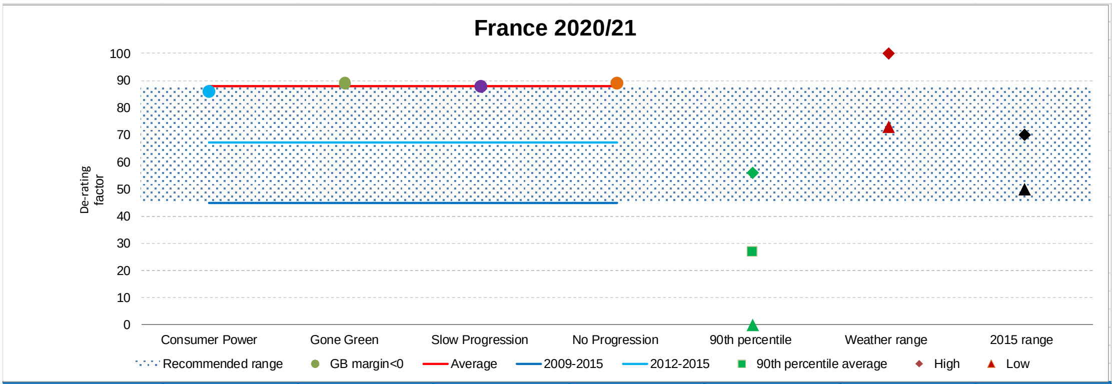
Figure 22: French interconnector de-rating factors 2017/18



	Consumer Power	Gone Green	Slow Progression	No Progression	90th percentile	Weather range	2015 range
GB margin<0	85	91	88	81			
Average	86	86	86	86			
2009-2015	45	45	45	45			
2012-2015	67	67	67	67			
90th percentile average					33		
High					100	100	70
Low					0	70	50
Recommended High	86	86	86	86	86	86	
Recommended Low	45	45	45	45	45	45	

The proposed de-rating range for France 2017/18 is 45% to 86% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis. Compared to last year the top of the range has increased but the bottom is broadly unchanged.

Figure 23: French interconnector de-rating factors 2020/21



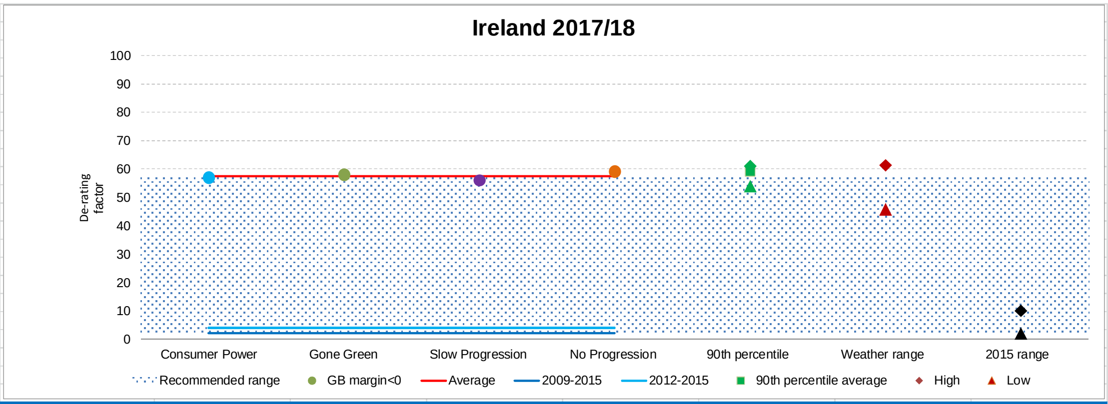
	Consumer Power	Gone Green	Slow Progression	No Progression	90th percentile	Weather range	2015 range
GB margin<0	86	89	88	89			
Average	88	88	88	88			
2009-2015	45	45	45	45			
2012-2015	67	67	67	67			
90th percentile average					27		
High					56	100	70
Low					0	73	50
Recommended High	88	88	88	88	88	88	
Recommended Low	45	45	45	45	45	45	

The proposed range for France 2020/21 is 45% to 88% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis.

The seven year historical factors represent the risk to flows seen historically. The alternative is to use the shorter period because since the introduction of market coupling in 2014 flows have been much more aligned to market prices, but there is not a long enough period to use. The 90th percentile figures indicate a drop in flows at extremes, supporting the lower end of the range. When France gets very cold demand increases several GW above domestic generation capacity potentially restricting the flow to GB. Using just the last four years may not include enough cold periods to reflect this risk. Additional downward pressures for the French interconnectors are the introduction of a carbon price floor from January 2017 and the potential for closures of some nuclear plants from 2018, to reduce the share of nuclear to 50% by 2025.

Ireland:

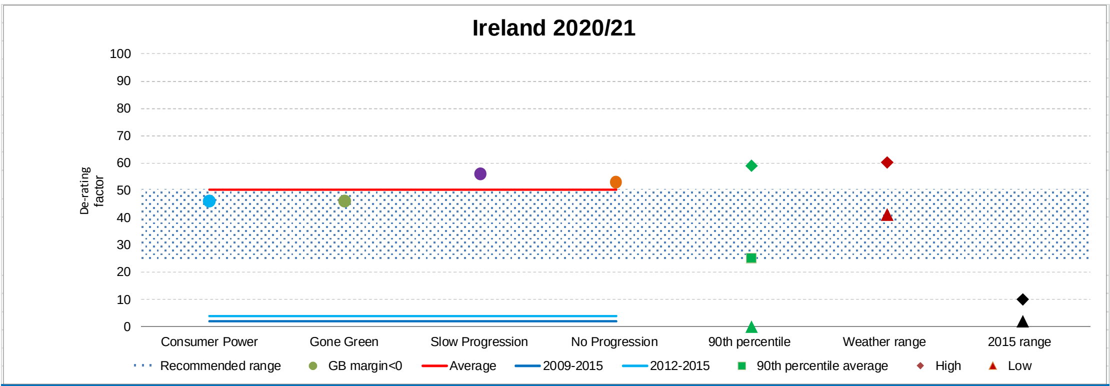
Figure 24: Irish interconnector de-rating factors 2017/18



	Consumer Power	Gone Green	Slow Progression	No Progression	90th percentile	Weather range	2015 range
GB margin<0	57	58	56	59			
Average	58	58	58	58			
2009-2015	2	2	2	2			
2012-2015	4	4	4	4			
90th percentile average					59		
High					61	61	10
Low					54	46	2
Recommended High	58	58	58	58	58	58	
Recommended Low	2	2	2	2	2	2	

The results for Ireland are influenced by a number of modelling assumptions that switches the Irish interconnectors from exports to Ireland during the winter evening peak hours to imports. These include modelling Ireland as a single price zone thus ignoring any internal constraints between the north and south but allowing for constraint on the GB network. The modelling also assumes that I-SEM, the new Irish electricity market, will go live as planned in autumn 2017 and will be fully effective immediately. This is expected to ensure that electricity flows in alignment with the price differentials between Ireland and GB. The proposed de-rating range for Ireland 2017/18 is 2% to 58% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry history. The high figure assumes that I-SEM starts as planned in 2017 and has the expected impact with flows being consistent with modelled price differentials. The lower bound reflects historical risks and uncertainty about the effectiveness of I-SEM in driving changes in 2017/18. There is currently no market coupling with Ireland so there is little difference between the seven and four year history.

Figure 25: Irish interconnector de-rating factors 2020/21

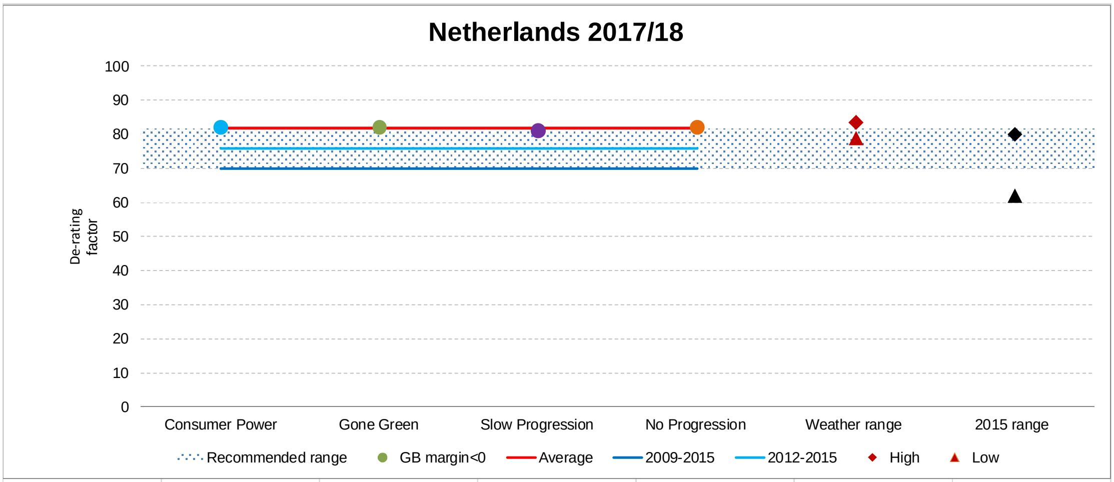


	Consumer Power	Gone Green	Slow Progression	No Progression	90th percentile	Weather range	2015 range
GB margin<0	46	46	56	53			
Average	50	50	50	50			
2009-2015	2	2	2	2			
2012-2015	4	4	4	4			
90th percentile average					25		
High					59	60	10
Low					0	41	2
Recommended High	50	50	50	50	50	50	
Recommended Low	25	25	25	25	25	25	

The proposed de-rating range for Ireland 2020/21 is 25% to 50% with the upper bound set to the average of the four scenarios and the lower bound from the 90th percentile. Irish margins are falling in 2020/21 resulting in a lower upper bound from the Baringa model average compared to 2017/18. We have assumed that by 2020/21 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. Risks of low imports still exist so we have used the 90th percentile average to set the lower bound. 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 retain the Pöyry history as the 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. Compared to last year the upper bound is significantly higher and the lower bound is also increased but has the effect of smoothing the transition in the ranges. For Ireland the de-rating factor has been calculated using the full capacity not TEC. The 80 GW Scottish import constraint has only been applied to flows and not the capacity.

Netherlands:

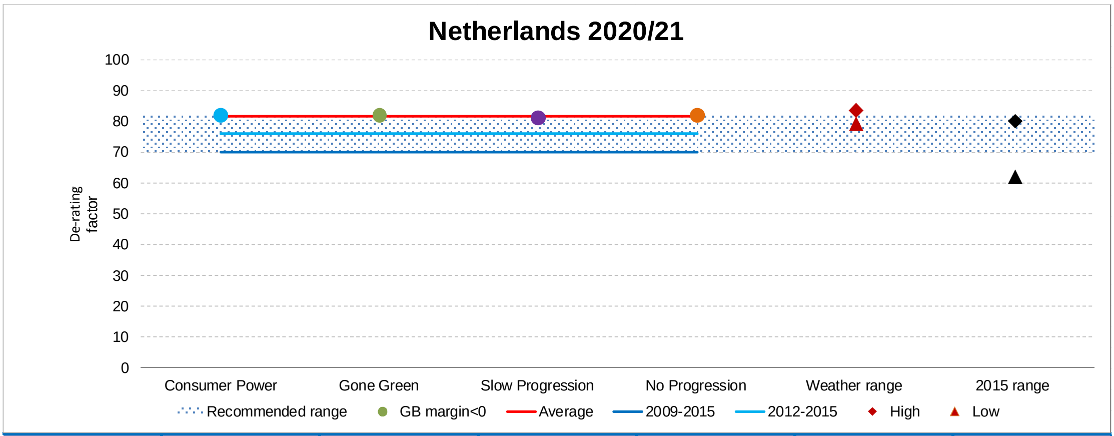
Figure 26: Netherlands interconnector de-rating factors 2017/18



	Consumer Power	Gone Green	Slow Progression	No Progression	Weather range	2015 range
GB margin<0	82	82	81	82		
Average	82	82	82	82		
2009-2015	70	70	70	70		
2012-2015	76	76	76	76		
High					83	80
Low					79	62
Recommended High	82	82	82	82	82	
Recommended Low	70	70	70	70	70	

The results for the Netherlands show very little variation between methodologies. The proposed de-rating range for the Netherlands for 2017/18 is 70% to 82% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis. The Netherlands figures are based on a TEC of 1.2 GW but a maximum flow of 1 GW. 82% is therefore close to full imports and the four year Pöyry average is not much lower at 76%. There is little difference between the two historical figures so the longer period has been used to reflect risks to flows seen historically. Compared to last year the range is broadly similar but slightly narrower.

Figure 27: Netherlands interconnector de-rating factors 2020/21

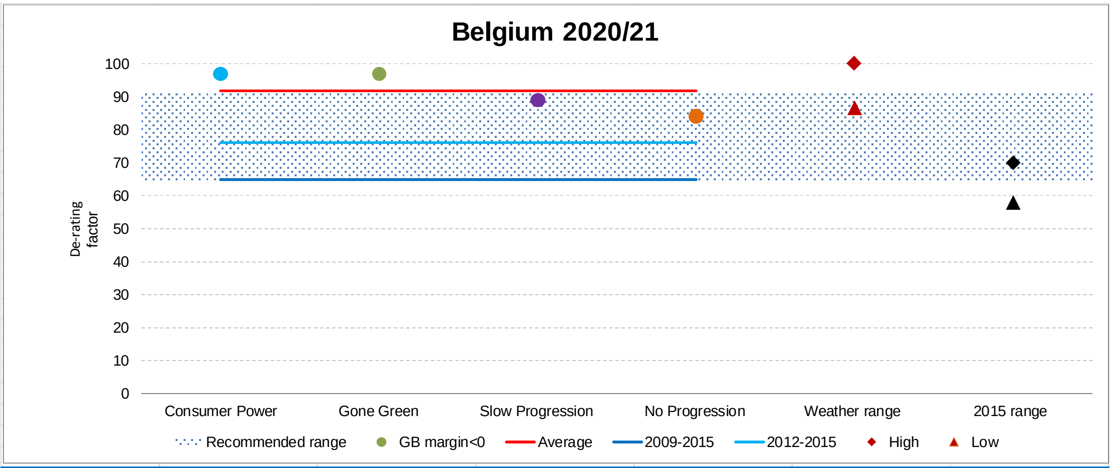


	Consumer Power	Gone Green	Slow Progression	No Progression	Weather range	2015 range
GB margin<0	82	82	81	82		
Average	82	82	82	82		
2009-2015	70	70	70	70		
2012-2015	76	76	76	76		
High					83	80
Low					79	62
Recommended High	82	82	82	82	82	
Recommended Low	70	70	70	70	70	

The proposed de-rating range for the Netherlands for 2020/21 is 70% to 82% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis.

Belgium:

Figure 28: Belgium interconnector de-rating factors 2020/21

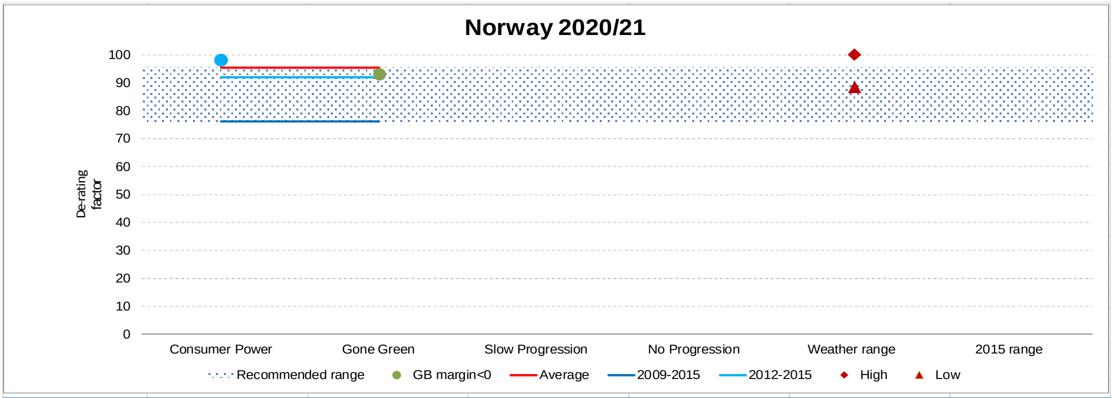


	Consumer Power	Gone Green	Slow Progression	No Progression	Weather range	2015 range
GB margin<0	97	97	89	84		
Average	92	92	92	92		
2009-2015	65	65	65	65		
2012-2015	76	76	76	76		
High					100	70
Low					87	58
Recommended High	92	92	92	92	92	
Recommended Low	65	65	65	65	65	

The modelling assumes that Belgium's nuclear power is still operating ensuring that Belgium's generation is not much less than peak demand. The history figure is based on historical price differentials between the two markets. The proposed de-rating range for Belgium for 2020/21 is 65% to 92% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis. The longer history is used for the lower bound to reflect risks to flows seen historically. The alternative is to use a shorter historical period based on market coupling being introduced across Europe but as market coupling did not go live for Great Britain until 2014 there is not a long enough period to use. Compared to last year the range is wider and higher. This range could be reduced to reflect lower availability during commissioning.

Norway:

Figure 29: Norway interconnector de-rating factors 2020/21



	Consumer Power	Gone Green	Slow Progression	No Progression	Weather range	2015 range
GB margin<0	98	93				
Average	96	96				
2009-2015	76	76				
2012-2015	92	92				
High					100	
Low					89	
Recommended High	96	96	96	96	96	
Recommended Low	76	76	76	76	76	

Norway only features in Consumer Power and Gone Green and was not part of the 2015 analysis for the 2019/20 auction. The history figure is based on historical price differentials between the two markets. The proposed de-rating range for Norway for 2020/21 is 76% to 96% with the upper bound set to the average of the four scenarios and the lower bound from the Pöyry analysis. (The impact of market coupling on the Pöyry figure is not relevant for Norway because there is not an existing link.) A key driver of Norwegian prices is the level of water in the reservoirs. A longer period of history ensures a greater range of weather events are represented so for Norway the seven year history should set the bottom of the range and the four year history isn't considered as an appropriate alternative.

Summary

Table 15 shows the recommended ranges for de-rating factors in 2017/18 and 2020/21 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 undertaken by Baringa using their pan-European market model and Pöyry's analysis on historical performance. The top of the de-rating factor ranges are set by the Baringa modelling with Pöyry's analysis of seven historical years setting the bottom of the ranges for all but Ireland in 2020/21. We have assumed that by 2020/21 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 90th percentile from the Baringa's results to set the lower bound. This assumption is not certain and if market coupling does not develop in Ireland then the Pöyry history would 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.

For the top of the ranges there was really only one option with Baringa's analysis providing robust market modelling while the other option considered was based on analysis around temperatures and wind speeds which was less robust but in most cases gave similar results anyway to Baringa's analysis.

When considering what to base the bottom of the ranges on for each country we considered a number of alternatives including Pöyry's historical based analysis, analysis of temperatures & wind speeds and different percentiles of Baringa's distribution of results. While each of them has some merit there are also some limitations to their robustness. For instance the average based on four years history while relating to the period when market coupling was introduced across Europe is too short to include some of the potential risks to flow e.g. for Norway when droughts affected hydro output in 2009 and 2010. For the average based on seven years of history this covers a wider range of risks but also covers periods when the markets were operating less efficiently. The impact of using seven or four years is illustrated in Table 15 below. For the other two options the temperatures and wind speeds did not provide a consistent picture across countries nor had any material effect on the range. The different percentiles of the results only provided insights into changing flows for France and Ireland.

Table 15: De-rating factor ranges by country

% 's		France	Netherlands	Ireland	Belgium	Norway
2017/18	High	86	82	58	-	-
2017/18	Low	45	70	2	-	-
2017/18	4-year history	67	76	4		
2020/21	High	88	82	50	92	96
2020/21	Low	45	70	25	65	76
2020/21	4-year history	67	76	4	76	92

5. Results and Recommendation for 2020/21 T-4 Auction

This chapter presents the results for 2020/21 only from the modelling of the scenarios and sensitivities relevant to 2020/21. Results for 2017/18 and 2018/19 can be found in chapters 6 and 7 respectively. Further information on capacity requirements in years out to 2030/31 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 2016 ECR. The agreed sensitivities to model for 2020/21 cover non-delivery, weather, plant availability 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 Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non Delivery (NON DEL): 9 sensitivities in 400 MW increments up to 3600 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.

The Base Case also assumes that some capacity contracted for 2020/21 in previous T-4 auctions is not able to honour its awarded contracts whereas the DECC scenario assumes all previously contracted capacity honours its contracts.

Table 16: Modelled de-rated capacities and peak demands - 2020/21

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Total derated capacity (GW)	ACS Peak (GW)
DECC Scenario	DECC	45.9	18.1	6.4	64.0	61.2
Base Case Warm Winter	BC_WARM	46.1	15.4	3.5	61.5	60.2
Base Case Low Demand	BC_LOW_DEMAND	46.7	15.5	3.5	62.2	59.0
Slow Progression	SP	47.0	15.3	3.5	62.2	59.9
No Progression	NP	47.1	16.1	4.8	63.2	60.8
Base Case High Wind	BC_HIGH_WIND	47.5	15.7	3.5	63.3	60.2
Base Case	BC	47.7	15.6	3.5	63.2	60.2
Base Case Low Availability	BC_LOW_AVAIL	47.7	15.6	3.5	63.3	60.2
Base Case High Availability	BC_HIGH_AVAIL	47.7	15.5	3.5	63.2	60.2
Base Case Low Wind	BC_LOW_WIND	47.8	15.3	3.5	63.1	60.2
Base Case Non Delivery Scenario: -400	BC_NON_DEL_400	48.1	15.2	*	63.2	60.2
Gone Green	GG	48.1	14.2	1.8	62.3	59.7
Base Case Non Delivery Scenario: -800	BC_NON_DEL_800	48.5	14.8	*	63.2	60.2
Base Case Cold Winter	BC_COLD	48.6	15.6	3.5	64.2	60.2
Base Case High Demand	BC_HIGH_DEMAND	48.8	15.6	3.5	64.4	61.4
Base Case Non Delivery Scenario: -1200	BC_NON_DEL_1200	48.9	14.4	*	63.2	60.2
Base Case Non Delivery Scenario: -1600	BC_NON_DEL_1600	49.3	14.0	*	63.2	60.2
Consumer Power	CP	49.5	14.1	1.8	63.5	60.7
Base Case Non Delivery Scenario: -2000	BC_NON_DEL_2000	49.7	13.6	*	63.2	60.2
Base Case Non Delivery Scenario: -2400	BC_NON_DEL_2400	50.1	13.2	*	63.2	60.2
Base Case Non Delivery Scenario: -2800	BC_NON_DEL_2800	50.5	12.8	*	63.2	60.2
Base Case Non Delivery Scenario: -3200	BC_NON_DEL_3200	50.9	12.4	*	63.2	60.2
Base Case Non Delivery Scenario: -3600	BC_NON_DEL_3600	51.3	12.0	*	63.2	60.2

Scenario Colour Key

Gone Green
Slow Progression
No Progression
Consumer Power
DECC Scenario
Base Case

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

* Previously contracted not identified for non-delivery sensitivities as non-delivery could be split between plants contracted in previous auctions and plants contracted in future auctions.

N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with 3, 14 or 15 year contracts secured for 2020/21 in the 2018/19 and 2019/20 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.

The warm winter and 3600 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2020/21 (46.1 GW to 51.3 GW).

5.3 Recommended Capacity to Secure

The table above 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 2020/21 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 DECC and the PTE has been used to select an initial capacity to secure value in 2020/21 taking account of the costs of under or over securing for all potential outcomes.

The LWR methodology is explained 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 to select a scenario/sensitivity combination 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 an initial capacity to secure for 2020/21 of 49.5 GW (49.48 GW before rounding) based on the Consumer Power scenario. As this is a FES scenario, a small adjustment is required to bring it into line with the DFA Incentive by selecting the nearest Base Case sensitivity based on the DFA Incentive demand level (as per section 2.6.3). In this case the nearest sensitivity is the 2000 MW non-delivery sensitivity (49.65 GW before rounding) that is marginally closer than the 1600 MW non-delivery sensitivity (49.25 GW before rounding).

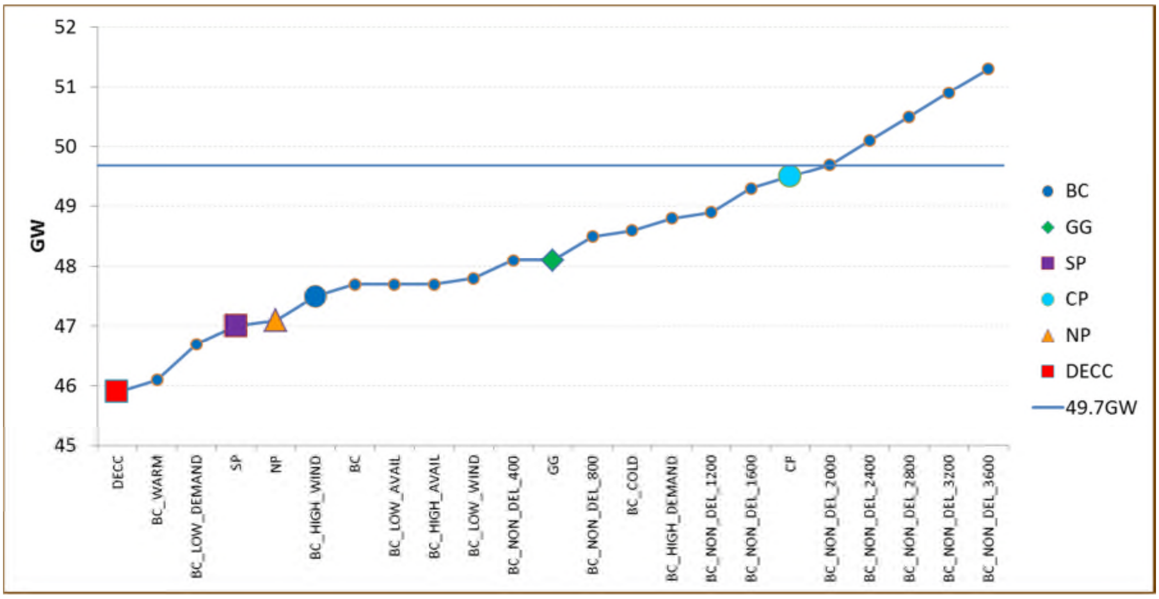
This leads to a recommended capacity to secure for 2020/21 of **49.7 GW** derived from the requirement of the Base Case 2000MW non-delivery sensitivity. This does not take account of a different clearing price to net CONE resulting from the auction as our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. It also excludes any capacity secured in earlier auctions for 2020/21 that is assumed in the Base Case

In general, when compared to the analysis for 2019/20 in the 2015 ECR, the 2016 scenarios and sensitivities for 2020/21 contain higher levels of CM-ineligible de-rated capacity at peak due to higher contribution from renewables (see Annex for breakdown), in part due to the new offshore power curve, as well as higher levels of assumed ineligible autogeneration below 2 MW[28]. However the reduction in total CM-eligible capacity requirement due to higher levels of ineligible capacity is offset by using a wider range of non-delivery sensitivities that increases the requirement in the LWR analysis. The warm winter sensitivity is the key to the LWR result as it is the sensitivity that sets the highest regret cost for the recommended capacity level (see Annex for more details on how regret costs are determined in the LWR calculation).

The following chart illustrates the full range of potential capacity levels (from National Grid scenarios and sensitivities) plus the DECC scenario and identifies the Least Worst Regret 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.

[28] 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 30: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2020/21



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 2020/21, 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 avoid 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 49.7 GW would result in 18 out of 22 National Grid cases (plus the DECC scenario) 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 early capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by w, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Government upon confirming auction parameters to National Grid prior to auction guidelines will determine how much capacity to hold back for the 2020/21 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*
- Long Term STOR contracts (currently signed) need to be excluded (pre-qualification could change this) – 0.4GW**

Therefore, the recommended total capacity to secure through the 2017/18 early auction will be:

- 49.7 GW - w - x - y - z - 0.4GW

*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. Furthermore, we expect DSR will bid into the transitional auction.

** There is currently around 400MW signed up under long term STOR contracts

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 49.7 GW could result in a differing capacity volume depending on the clearing price set by the marginal capacity. The tolerances are set by DECC 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.

6. Results and Recommendation for 2017/18 Early Auction

This chapter presents the results for 2017/18 only from the modelling of the scenarios and sensitivities relevant to 2017/18. Results for 2018/19 and 2020/21 can be found in chapters 7 and 5 respectively. Further information on capacity requirements in years out to 2030/31 can be found in Section 3.12.

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. Chapter 3 describes the scenarios and sensitivities modelled for the 2016 ECR. The agreed sensitivities to model for 2017/18 cover non-delivery, weather, plant availability 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 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.

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.

Table 17: Modelled de-rated capacities and peak demands – 2017/18

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Total derated capacity (GW)	ACS Peak (GW)
Base Case Warm Winter	BC_WARM	51.0	10.5	61.5	60.5
Base Case Low Demand	BC_LOW_DEMAND	51.6	10.5	62.2	59.3
Gone Green	GG	52.4	10.8	63.2	60.3
Base Case High Availability	BC_HIGH_AVAIL	52.7	10.5	63.2	60.5
Base Case High Wind	BC_HIGH_WIND	52.7	10.7	63.4	60.5
Slow Progression	SP	52.8	10.6	63.4	60.3
Base Case	BC	52.8	10.5	63.3	60.5
Consumer Power	CP	53.0	10.3	63.3	60.7
Base Case Low Availability	BC_LOW_AVAIL	53.0	10.6	63.6	60.5
Base Case Low Wind	BC_LOW_WIND	53.0	10.3	63.3	60.5
DECC Scenario	DECC	53.1	10.9	64.0	61.1
Base Case Non Delivery Scenario: -400	BC_NON_DEL_400	53.2	10.1	63.3	60.5
No Progression	NP	53.4	10.1	63.5	60.9
Base Case Non Delivery Scenario: -800	BC_NON_DEL_800	53.6	9.7	63.3	60.5
Base Case Cold Winter	BC_COLD	53.8	10.6	64.4	60.5
Base Case Non Delivery Scenario: -1200	BC_NON_DEL_1200	54.0	9.3	63.3	60.5
Base Case High Demand	BC_HIGH_DEMAND	54.1	10.6	64.7	61.7
Base Case Non Delivery Scenario: -1600	BC_NON_DEL_1600	54.4	8.9	63.3	60.5
Base Case Non Delivery Scenario: -2000	BC_NON_DEL_2000	54.8	8.5	63.3	60.5
Base Case Non Delivery Scenario: -2400	BC_NON_DEL_2400	55.2	8.1	63.3	60.5
Base Case Non Delivery Scenario: -2800	BC_NON_DEL_2800	55.6	7.7	63.3	60.5

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

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

N.B. ACS Peak demand excludes reserve for largest infeed loss. Note that the non-delivery sensitivities have been modelled by reducing the "Outside CM" capacity.

The warm winter and 2800 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2017/18 (51.0 to 55.6 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 capacity was selected based on one model run but in 2017/18 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 DECC and the PTE has been used to select a single capacity to secure value in 2017/18 taking account of the costs of under or over securing for all potential outcomes.

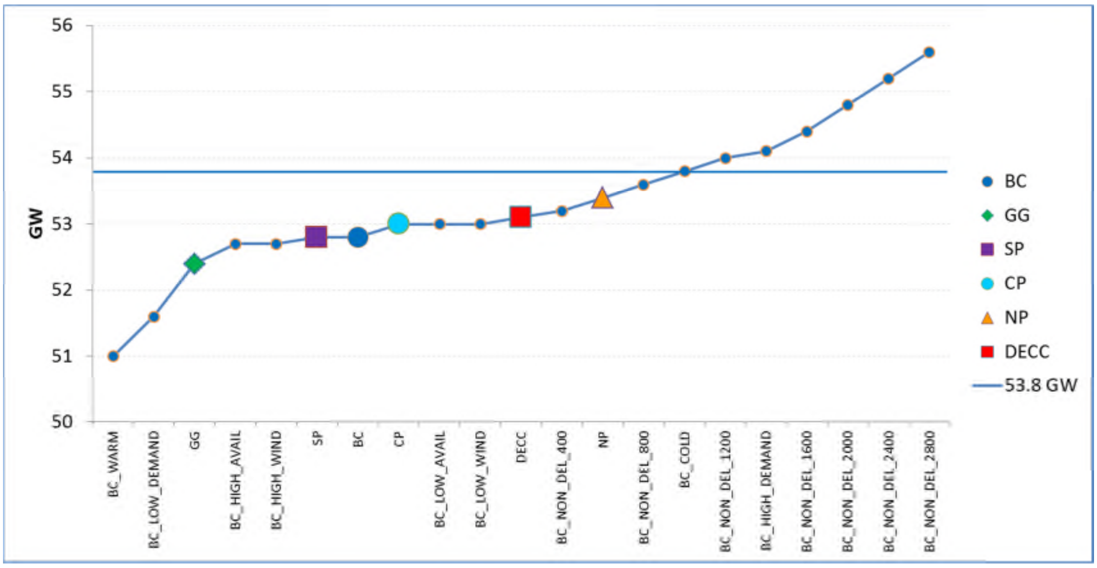
The LWR methodology is explained in Annex. As per previous ECR analysis, it uses a cost of capacity £49/kW/yr and an energy unserved cost of £17,000/MWh to select a scenario/sensitivity combination from which the recommended capacity to secure is derived.

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 2017/18 of **53.8 GW** derived from the requirement of the Base Case Cold Winter 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.

In general, when compared to the analysis for 2018/19 in the 2014 ECR, the 2016 scenarios and sensitivities for 2017/18 contain higher levels of CM-ineligible de-rated capacity at peak due to higher contribution from renewables (see Annex for breakdown), in part due to the new offshore power curve, as well as higher levels of assumed ineligible autogeneration below 2 MW. [29] However the reduction in total CM-eligible capacity requirement due to higher levels of ineligible capacity is offset by higher peak demands and by using a wider range of non-delivery sensitivities that increases the requirement in the LWR analysis. The 2800 MW non-delivery sensitivity is the key to the LWR result as it is the sensitivity that sets the highest regret cost for the recommended capacity level (see Annex for more details on how regret costs are determined in the LWR calculation).

The following chart illustrates the full range of potential capacity levels (from National Grid scenarios and sensitivities) plus the DECC scenario and identifies the Least Worst Regret 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 31: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2017/18



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 2017/18, 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

[29] 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

from interconnectors) more frequently/in higher volumes to avoid 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 53.8 GW would result in 14 out of 20 National Grid cases (plus the DECC scenario) being covered.

6.3.2 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 early capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by x, y and z below):

- 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*
- Long Term STOR contracts (currently signed) need to be excluded (pre-qualification could change this) – 0.4GW**

Therefore, the recommended total capacity to secure through the 2017/18 early auction will be:

- 53.8 GW - x - y - z - 0.4GW

*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.

** There is currently around 400MW signed up under long term STOR contracts

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 53.8 GW could result in higher or lower capacity depending on the clearing price set by the marginal capacity and the demand curve structure in the auction. The tolerances are set by DECC in order to limit gaming opportunities.

7. Results and Indicative T-1 Requirement for 2018/19 Auction

This chapter presents the results for 2018/19 only from the modelling of the scenarios and sensitivities relevant to 2018/19. We are not making a recommendation for 2018/19: these are provided for information only and have been used to derive an indicative requirement for the 2018/19 T-1 auction Results and recommendations for 2017/18 and 2020/21 can be found in chapters 5 and 6 respectively. Further information on capacity requirements in years out to 2030/31 can be found in section 3.11.

7.1 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 1900 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, weather, 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): 9 sensitivities in 400 MW increments up to 3600 MW.
- 750 MW Continental interconnector imports (IC 750IMPORTS): 300 MW net GB flow (including 450 MW exports to Ireland)
- 1500 MW Continental interconnector imports (IC 1500IMPORTS): 1300 MW net GB flow (including 200 MW exports to Ireland)
- 2250 MW Continental interconnector imports (IC 2250IMPORTS): 2500 MW net GB flow (including 250 MW imports from Ireland)
- 3000 MW Continental interconnector imports (IC 3000IMPORTS): 3500 MW net GB flow (including 500 MW imports from Ireland)

7.2 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.

The Base Case also assumes that some capacity contracted for 2018/19 in the previous T-4 auction is not able to honour its awarded contracts. For example, the

Base Case assumes early closures of some contracted coal plants as well as delays to new build capacity, which in total amounts to 4.3 GW in 2018/19.

Table 18: Modelled de-rated capacities and peak demands – 2018/19

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Total derated capacity (GW)	ACS Peak (GW)
Base Case Warm Winter	BC_WARM	3.9	57.5	43.3	61.3	60.3
Interconnectors 3000 MW Imports	BC_IC_3000IMPORT	4.0	59.2	43.3	63.3	60.3
No Progression	NP	4.4	59.4	45.9	63.8	60.8
DECC Scenario	DECC	4.5	59.0	46.0	63.4	60.5
Base Case Low Demand	BC_LOW_DEMAND	4.5	57.6	43.3	62.1	59.1
Base Case High Availability	BC_HIGH_AVAIL	4.6	58.5	44.2	63.1	60.3
Interconnectors 2250 MW Imports	BC_IC_2250IMPORT	5.1	58.3	43.3	63.3	60.3
Slow Progression	SP	5.3	57.9	44.1	63.2	60.1
Base Case High Wind	BC_HIGH_WIND	5.5	57.8	43.3	63.3	60.3
Base Case	BC	5.7	57.6	43.3	63.3	60.3
Gone Green	GG	5.8	57.4	43.2	63.2	60.2
Base Case Low Wind	BC_LOW_WIND	5.9	57.4	43.3	63.3	60.3
Consumer Power	CP	6.0	57.4	43.3	63.4	60.4
Base Case Non Delivery Scenario: -400	BC_NON_DEL_400	6.1	57.2	*	63.3	60.3
Interconnectors 1500 MW Imports	BC_IC_1500IMPORT	6.3	57.0	43.3	63.3	60.3
Base Case Non Delivery Scenario: -800	BC_NON_DEL_800	6.5	56.8	*	63.3	60.3
Base Case Cold Winter	BC_COLD	6.7	57.7	43.3	64.4	60.3
Base Case Low Availability	BC_LOW_AVAIL	6.7	56.8	42.4	63.5	60.3
Base Case Non Delivery Scenario: -1200	BC_NON_DEL_1200	6.9	56.4	*	63.3	60.3
Base Case High Demand	BC_HIGH_DEMAND	6.9	57.6	43.3	64.5	61.5
Base Case Non Delivery Scenario: -1600	BC_NON_DEL_1600	7.3	56.0	*	63.3	60.3
Interconnectors 750 MW Imports	BC_IC_750IMPORTS	7.3	56.1	43.3	63.3	60.3
Base Case Non Delivery Scenario: -2000	BC_NON_DEL_2000	7.7	55.6	*	63.3	60.3
Base Case Non Delivery Scenario: -2400	BC_NON_DEL_2400	8.1	55.2	*	63.3	60.3
Base Case Non Delivery Scenario: -2800	BC_NON_DEL_2800	8.5	54.8	*	63.3	60.3
Base Case Non Delivery Scenario: -3200	BC_NON_DEL_3200	8.9	54.4	*	63.3	60.3
Base Case Non Delivery Scenario: -3600	BC_NON_DEL_3600	9.3	54.0	*	63.3	60.3

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

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

* Previously contracted not identified for non-delivery sensitivities as non-delivery could be split between plants contracted in previous auctions and plants contracted in future auctions.

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.

The warm winter and 3600 MW non-delivery sensitivity define the extremes of the capacity to secure range for 2017/18.

7.3 Indicative Capacity to Secure

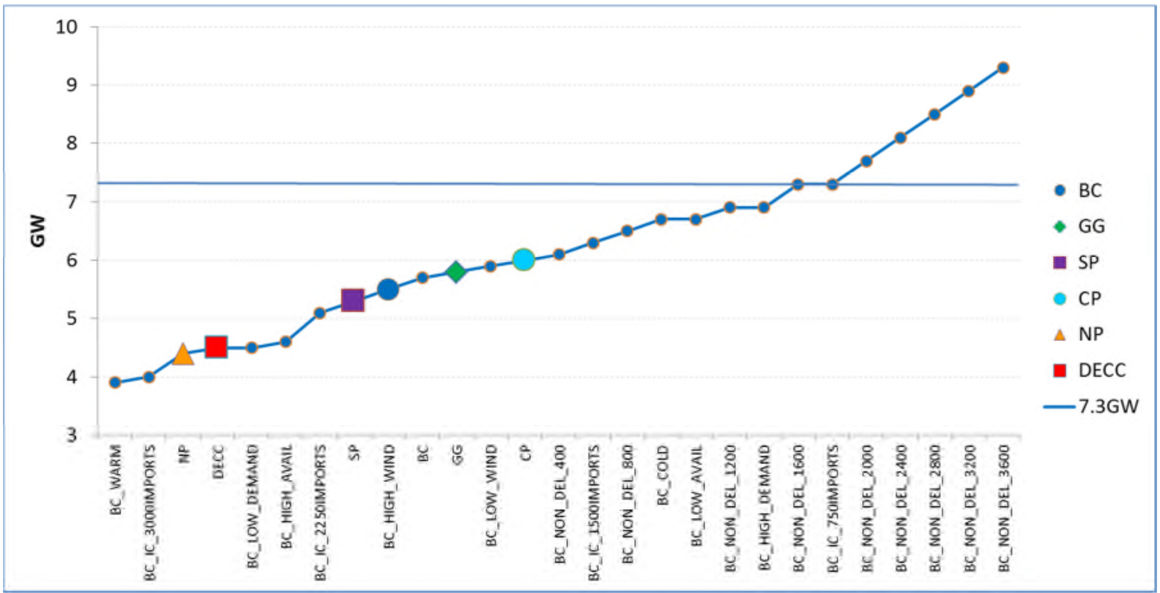
The table above shows the capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run but in 2018/19 the actual conditions matched a different model run then capacity will have either been over or under secured resulting in an LOLE higher or 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 DECC and the PTE has been used to select an indicative capacity to secure value in 2018/19 taking account of the costs of under or over securing for all potential outcomes.

The LWR methodology is explained 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 to select a scenario/sensitivity combination 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 an indicative capacity to secure for 2018/19 of **7.3 GW** derived from the requirement of the Base Case 1600MW sensitivity (and also the 750 MW continental imports sensitivity). This does not take account of a different clearing price to net CONE resulting from the auction as our indicative target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost.

The following chart illustrates the full range of potential capacity levels (from National Grid scenarios and sensitivities) plus the DECC scenario and identifies the Least Worst Regret indicative capacity. Note that this concentrates on the indicative target capacity alone.

Figure 32: Least Worst Regret indicative capacity to secure compared to individual scenario/sensitivity runs



7.3.1 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 avoid 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 7.3 GW would result in 21 out of 26 National Grid cases (plus the DECC scenario) being covered.

7.3.2 Adjustments to Indicative Capacity

The indicative 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 x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- 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*
- Long Term STOR contracts (currently signed) need to be excluded (pre-qualification could change this) – 0.4GW**

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

- 7.3 GW - x - y - z - 0.4GW

*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. Furthermore, we expect DSR will bid into the transitional auction.

** There is currently around 400MW signed up under long term STOR contracts

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.

An indicative de-rated capacity of 7.3 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 DECC in order to limit gaming opportunities.

7.3.3 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 49.2 GW of non-terminated awarded capacity, higher than the 48.6 GW target due to the low clearing price.

In general, when compared to the analysis for 2018/19 in the 2014 ECR, the 2016 scenarios and sensitivities for 2018/19 contain higher levels of CM-ineligible de-rated capacity at peak due to:

- higher renewables contribution (see Annex for breakdown) in part due to the new offshore power curve
- higher levels of assumed opted-out or ineligible (below 2 MW) autogeneration[30]
- 1.9 GW higher assumed imports at peak in the Base Case
- over-securing in the 2018/19 T-4 auction.

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:

- a wider range of non-delivery sensitivities that increases the requirement in the LWR analysis
- assumed closures of contracted coal plants and delays to new build capacity, totalling 4.3 GW in 2018/19 in the Base Case.
- the contracted capacity in the T-4 auction being greater than de-rated TEC
- “opted out but operational” plant closing
- 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

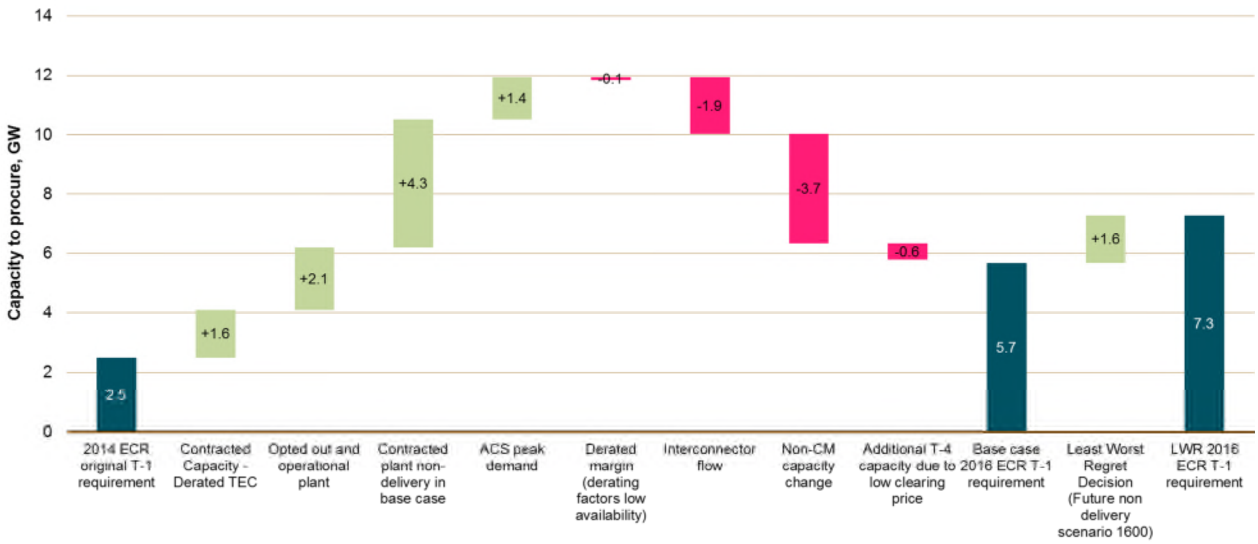
The Warm Winter sensitivity is key to the LWR result as it is the sensitivity that sets the highest regret cost for the recommended capacity level (see Annex for more details on how regret costs are determined in the LWR calculation).

This indicative view highlights the risk of contracted coal plant defaulting through closures (up to 2.7 GW in the Base Case plus up to a further 3.6 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 2017 ECR. For example, if the 2.7 GW of coal closures assumed in the Base Case did not occur, the 7.3 GW indicative requirement would potentially drop by 2.7 GW to 4.6 GW.

The following waterfall chart shows how the original 2.5 GW requirement for the 2018/19 T-1 auction (derived from the 2014 Slow Progression Low Availability sensitivity) has changed into an indicative requirement of 7.3 GW (derived from the 2016 Base Case 1600 MW non-delivery sensitivity).

[30] 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 33: Comparison with original 2018/19 T-1 requirement (de-rated)



A. Annex

A.1 Future Energy Scenario Method

As part of our stakeholder engagement we received feedback to clearly demonstrate how we build our scenarios and in particular understand more about our assumptions. We have created a new framework approach for 2016, detailing what assumptions we have made in the four scenarios across the political, economic, social and technological themes. Environmental assumptions are integrated across the four themes.

Scenario world

The first layer of our scenario framework is the scenario world. This contains the building blocks and inputs which are consistent across all of the scenarios; the number of scenarios, the axes on which they are placed and the fixed rules regarding security of supply. The two axes are, as last year, ‘Prosperity’ and ‘Green ambition’. The four scenario names are also the same as last year; Gone Green, Slow Progression, No Progression and Consumer Power. In 2015 there were three fixed rules across the four scenarios. The majority of stakeholders told us that the Levy Control Framework did not fit as a rule, as it is short term and can be changed. As such, for 2016 the Levy Control Framework is an assumption.

Electricity security of supply: In all scenarios, and across the whole study period, there will be sufficient electricity generation to meet the security of supply Reliability Standard. The government set a Reliability Standard for the GB market at a level which balances the impact of failure to deliver sufficient energy with the cost of the capacity required to provide that energy. This standard is three hours per year loss of load expectation (LOLE). LOLE measures the risk across the whole winter of demand exceeding supply under normal operation. It does not mean that there will be a loss of supply for three hours per year. It gives an indication of the amount of time the System Operator will need to use balancing tools across the winter period. These tools include voltage reduction (reducing voltage to reduce demand), maximum generation (accessing capacity which is outside of the generator’s usual operating range) and interconnector assistance (calling upon extra power flows from the continent). In most cases loss of load would be managed without significant impact on end consumers. The electricity generation backgrounds used in all of the FES scenarios have been developed to ensure that this standard is always met.

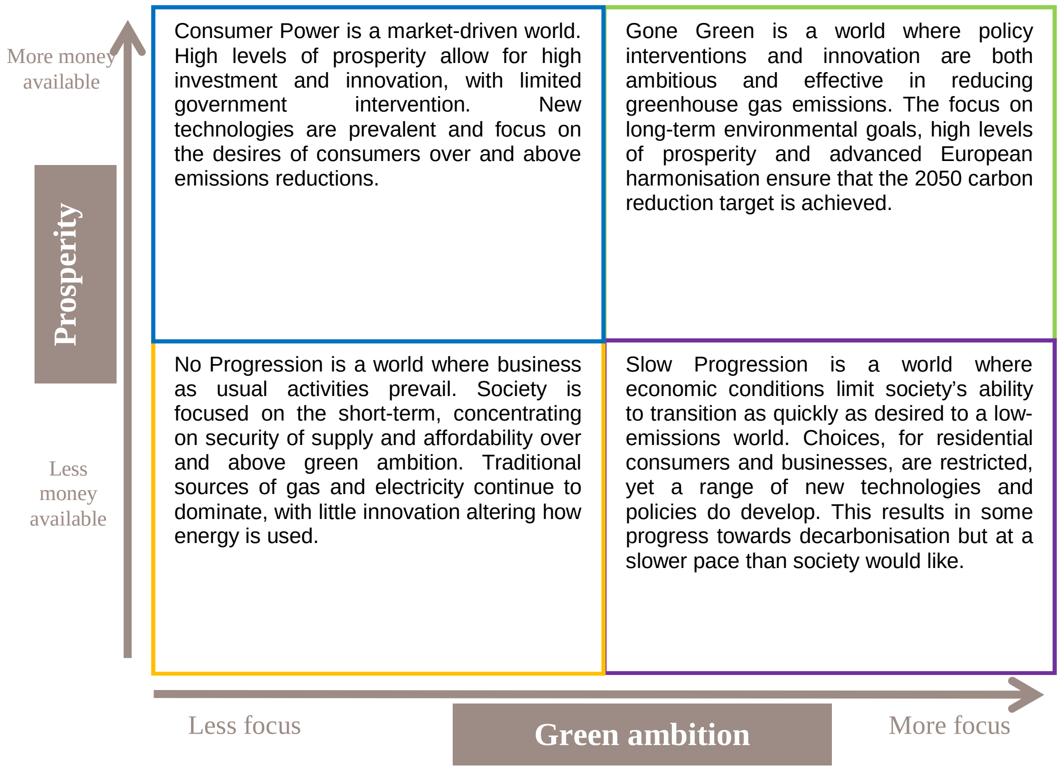
Assumptions

The second layer of the scenario framework is the assumptions; these are the variables which are flexed at high, medium or low in each scenario. They name specific policies, technologies or behaviours. The assumptions are grouped into political, economic, social and technological themes.

Model levers

The final layer of the scenario framework contains the model levers. These are the defined values used as inputs into the models in line with the high/medium/low level set for each assumption and show how the assumptions translate into inputs.

Figure 34: 2016 Scenarios Matrix



A.2 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.2.1 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 19: Annual Demand by scenario**

Annual Demand TWh	2016	2017	2018	2019	2020	2021	2022	2023
Base Case	332	330	329	327	326	323	320	320
Gone Green	332	329	326	325	322	321	321	322
Slow Progression	331	328	327	326	325	323	320	320
No Progression	333	332	332	331	330	329	328	327
Consumer Power	333	331	328	327	326	326	325	325

Annual Demand TWh	2024	2025	2026	2027	2028	2029	2030	2031
Base Case	320	320	319	319	318	318	319	319
Gone Green	324	326	329	332	336	340	344	349
Slow Progression	320	320	319	319	318	318	319	319
No Progression	326	325	325	324	323	322	322	323
Consumer Power	325	325	326	326	328	330	331	333

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

Table 20: Peak Demand by scenario**

Peak Demand GW	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Base Case	60.9	60.5	60.3	60.2	60.2	59.8	59.5	59.4
Gone Green	60.8	60.3	60.2	59.9	59.7	60.0	60.9	61.0
Slow Progression	60.8	60.3	60.1	59.8	59.9	59.8	59.5	59.4
No Progression	61.0	60.9	60.8	60.7	60.8	60.8	60.6	60.6
Consumer Power	61.0	60.7	60.4	60.3	60.7	61.0	60.9	60.9

Peak Demand GW	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Base Case	59.5	59.5	59.5	59.3	59.3	59.2	59.1
Gone Green	61.9	62.4	63.3	64.4	65.4	66.2	67.3
Slow Progression	59.5	59.5	59.5	59.3	59.3	59.2	59.1
No Progression	60.5	60.4	60.3	60.3	60.4	60.5	60.5
Consumer Power	61.2	61.4	61.7	61.9	62.3	62.6	63.2

**The definition of peak demand is unrestricted[31] GB National Demand plus demand supplied by distributed generation.

A.2.2 Generation Mix

The Generation mix (name plate capacity) for the 4 FES scenarios and Base Case from the DDM model:

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

Table 21: Base Case generation mix

Base Case Capacity Mix (GW)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CM eligible	63.9	60.1	54.9	58.2	56.4	55.3	55.5	58.0
Non-CM	23.3	25.1	33.0	30.5	29.9	31.6	34.7	36.2
Total peak capacity	87.2	85.2	87.9	88.7	86.4	86.9	90.2	94.2

Base Case Capacity Mix (GW)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
CM eligible	58.0	54.1	54.0	54.1	54.5	51.1	51.1
Non-CM	39.9	43.1	45.1	45.0	45.2	49.9	50.7
Total peak capacity	97.9	97.2	99.1	99.2	99.7	100.9	101.7

Table 22: Gone Green generation mix

Gone Green Capacity Mix (GW)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CM eligible	64.2	59.4	55.0	57.7	56.0	61.7	64.4	67.0
Non-CM	23.2	25.6	33.3	31.4	32.3	36.4	39.6	44.0
Total peak capacity	87.4	85.0	88.3	89.1	88.3	98.0	103.9	111.1

Gone Green Capacity Mix (GW)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
CM eligible	66.7	68.6	56.6	60.8	59.1	59.1	59.6
Non-CM	47.9	51.5	54.9	54.7	60.1	64.0	69.0
Total peak capacity	114.6	120.0	111.5	115.6	119.1	123.1	128.6

Table 23: Slow Progression generation mix

Slow Progression Capacity Mix (GW)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CM eligible	64.1	59.9	55.1	57.6	56.2	55.1	55.5	60.4
Non-CM	23.2	24.8	32.3	29.5	29.5	31.6	34.7	36.2
Total peak capacity	87.4	84.7	87.4	87.1	85.7	86.7	90.2	96.6

Slow Progression Capacity Mix (GW)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
CM eligible	64.8	63.4	62.1	59.6	59.9	51.0	50.6
Non-CM	39.9	43.1	45.1	45.0	45.8	49.9	50.7
Total peak capacity	104.6	106.6	107.1	104.6	105.7	100.9	101.2

Table 24: No Progression generation mix

No Progression Capacity Mix (GW)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CM eligible	64.4	60.8	55.9	59.4	57.7	57.0	58.3	57.9
Non-CM	23.1	24.6	31.3	28.3	27.8	29.6	30.3	30.3
Total peak capacity	87.6	85.4	87.2	87.6	85.5	86.6	88.6	88.2

No Progression Capacity Mix (GW)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
CM eligible	57.0	60.3	59.1	59.7	58.6	58.5	57.8
Non-CM	31.7	32.9	34.7	34.9	35.7	36.2	36.3
Total peak capacity	88.7	93.2	93.8	94.6	94.3	94.8	94.1

Table 25: Consumer Power generation mix

Consumer Power Capacity Mix (GW)	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CM eligible	63.7	59.7	54.9	58.6	58.6	56.3	64.9	64.0
Non-CM	23.4	25.1	32.8	29.6	28.6	30.5	32.0	33.3
Total peak capacity	87.1	84.8	87.7	88.2	87.2	86.7	96.9	97.3

Consumer Power Capacity Mix (GW)	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
CM eligible	65.3	71.5	63.0	64.8	64.7	62.8	64.0
Non-CM	36.5	39.2	42.3	45.1	46.1	48.4	50.5
Total peak capacity	101.8	110.7	105.3	109.9	110.7	111.1	114.4

A.2.3 CM-ineligible Capacity

The following tables give a breakdown of de-rated CM ineligible capacity for the Base Case in 2020/21, 2017/18 and 2018/19.

Note that the ineligible capacity is less in 2020/21 than 2018/19 as it includes interconnection and some autogeneration above 2 MW that opted out of the T-4 auction for 2018/19.

Table 26: Breakdown of De-rated CM ineligible capacity for 2020/21

Generation type	Capacity (in GW)
Onshore Wind	2.7
Offshore Wind	1.9
Biomass	2.7
Autogeneration	1.7
Hydro	0.7
Landfill	0.9
Other	1.4
Total	12.1

Table 27: Breakdown of De-rated CM ineligible capacity for 2017/18

Generation type	Capacity (in GW)
Onshore Wind	2.5
Offshore Wind	1.4
Biomass	2.4
Autogeneration	1.6
Hydro	0.7
Landfill	0.9
Other	1.0
Total	10.5

Table 28: Breakdown of De-rated CM ineligible capacity for 2018/19

Generation type	Capacity (in GW)
Onshore Wind	2.7
Offshore Wind	1.6
Biomass	2.7
Autogeneration	2.5
Interconnection	1.9
Hydro	0.7
Landfill	0.9
Other	1.2
Total	**14.2**

A.2.4 Station Availabilities

These are the station availabilities used for the 4 FES scenarios, base case, DECC Scenario 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.

Table 29: Station availabilities by sensitivity

Generation Type	Base	High Availability	Low Availability
CCGT Pre 2018	**88%**	**90%**	**86%**
CCGT 2018/19	**88%**	**90%**	**86%**
CCGT 2019/20	**89%**	**91%**	**87%**
CCGT 2020/21	**90%**	**92%**	**88%**
CCGT post 2021	**90%**	**92%**	**88%**
Coal	87%	87%	87%
Nuclear (Existing)	**84%**	**89%**	**80%**
Nuclear (New)	**90%**	**90%**	**90%**
ACT Advanced	87%	87%	87%
ACT CHP	87%	87%	87%
ACT Standard	87%	87%	87%
AD	87%	87%	87%
AD CHP	87%	87%	87%
Autogeneration	90%	90%	90%
Biomass CHP	87%	87%	87%
Biomass Conversion	87%	87%	87%
Coal CCS	87%	87%	87%
CHP (large scale)	As CCGT	As CCGT	As CCGT
Dedicated Biomass	87%	87%	87%
EfW	87%	87%	87%
EfW CHP	87%	87%	87%
Gas CCS	**90%**	**92%**	**88%**
Gas Turbine	94%	94%	94%
Geothermal	87%	87%	87%
Geothermal CHP	87%	87%	87%
Hydro	86%	86%	86%
Landfill	87%	87%	87%
OCGT	94%	94%	94%
Oil	85%	85%	85%
Pumped storage	96%	96%	96%
Sewage Gas	87%	87%	87%
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.2.5 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 30: Reserve to cover largest infeed loss by scenario

In Feed Loss GW	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Base Case	0.9	0.9	1.0	1.0	1.3	1.3	2.2	2.2
Gone Green	0.9	0.9	1.0	1.0	1.3	2.2	2.1	2.2
Slow Progression	0.9	0.9	1.0	1.0	1.0	1.0	2.2	2.2
No Progression	0.9	0.9	1.0	1.0	1.0	1.0	2.2	2.2
Consumer Power	0.9	0.9	1.0	1.3	1.3	2.2	2.2	2.2

In Feed Loss GW	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Base Case	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Gone Green	2.1	2.1	2.1	2.1	2.1	2.1	2.0
Slow Progression	2.2	2.2	2.2	2.2	2.2	2.2	2.2
No Progression	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Consumer Power	2.2	2.2	2.2	2.2	2.3	2.3	2.3

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

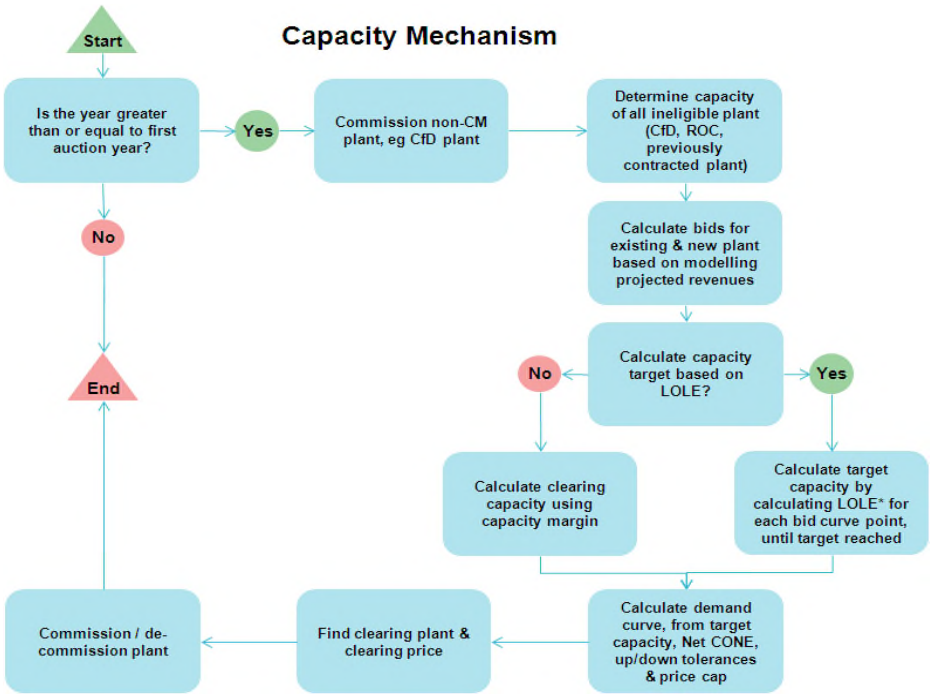
A.3 Detailed Modelling Approach

The following describes in more detail the modelling approach used in this report and expands on Section 3.1.

A.3.1 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 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 is has been used in this analysis to determine the capacity to secure. The following diagram illustrates the process at a high level:

Figure 35: Capacity Market flow chart[32]



2020/21 Modelling Steps

The key steps in the modelling of the capacity to secure from 2020/21 are outlined below:

1. The model first determines whether an auction should be run. For the 2020/21 analysis, the first auction simulated is in 2016 for delivery in 2020/21. The model assumes that an auction is run in all subsequent years from 2016.

2. The generation capacity described in Chapter 3.6 generation (plus demand side response in 3.5) 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 is included in the modelling as this plant is determined by the underlying scenario. 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, 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.

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

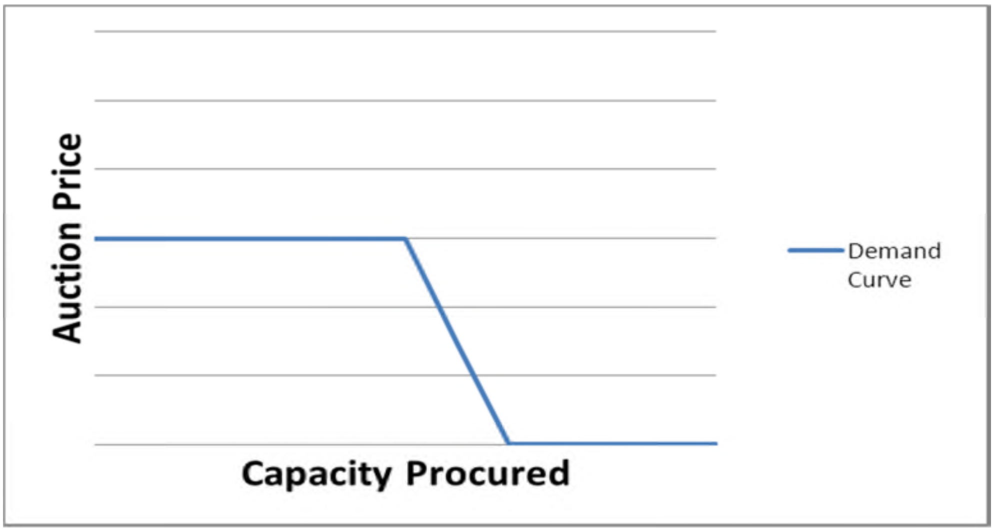
4. All existing and potential new capacity is ranked by their bids into the auction based on modelled revenues and expenditure. Interconnection is assumed to bid in at zero since the DDM does not model the economics of generation in interconnected countries.

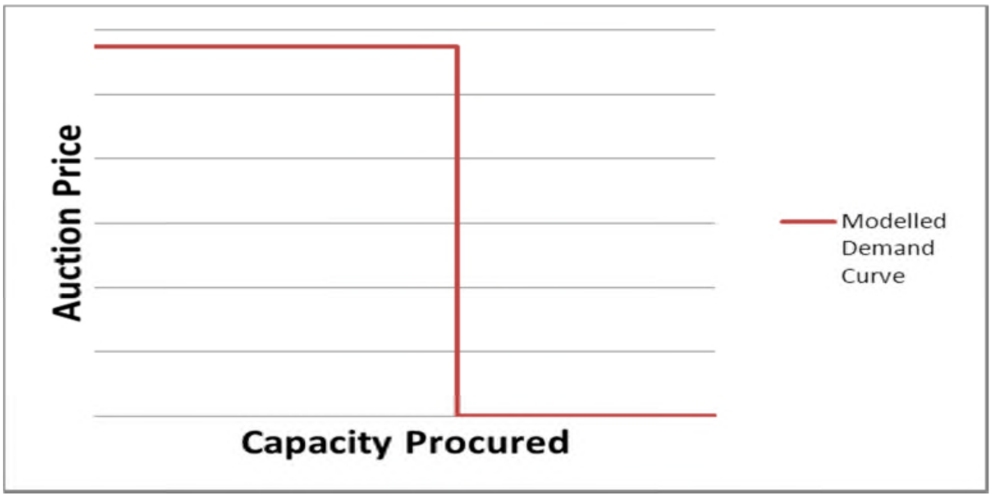
5. The model has the option to target either an LOLE or a capacity margin. For this analysis a target LOLE of 3 hours is used.

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 Baringa'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. Under normal running the model will use an auction demand curve (illustrated in Figure 36a), which will allow the model to determine a level of capacity taking into account the cost of capacity which enters the auction. For this analysis, the capacity to secure has to hit exactly 3 hours LOLE, so the demand curve has been altered in order to hit exactly 3 hours LOLE and not be allowed to secure more or less capacity (illustrated in Figure 36b). Also the auction cap has been raised well above the 75 £/kW so this allows the model to contract the capacity required:

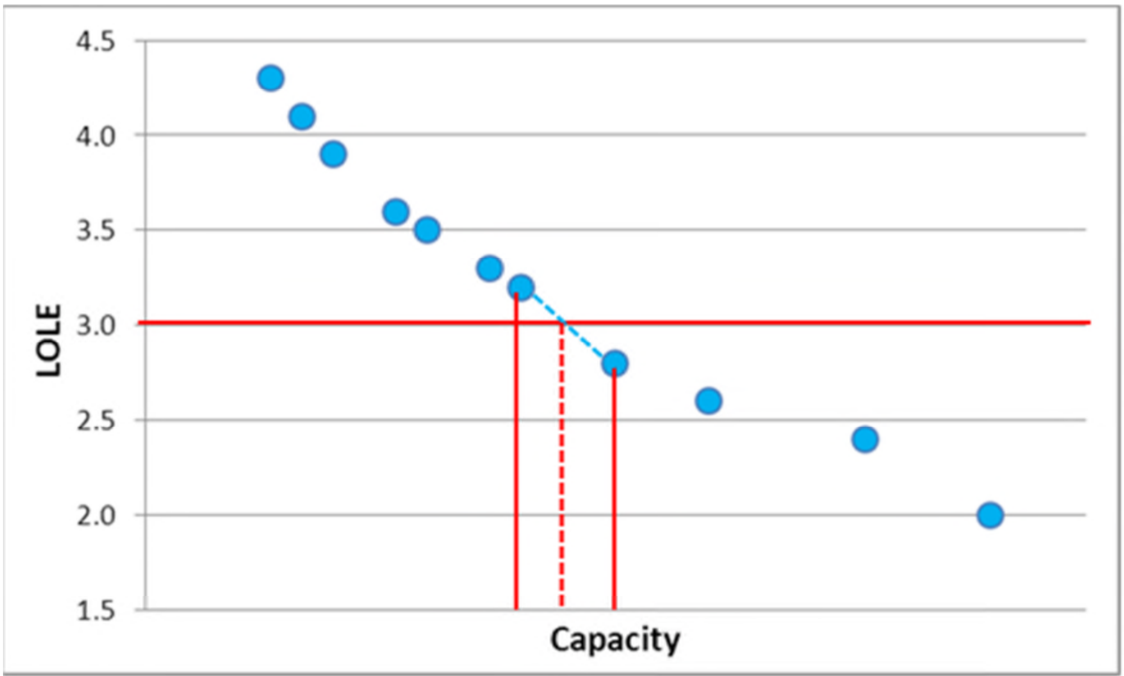
Figure 36: a) Realistic and b) Modelled Demand Curve





8. Given the model has to hit the 3 hours LOLE by using a combination of new and existing plants and demand side response and these plants are 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 37: Model interpolation to achieve 3 hours LOLE



9. This de-rated capacity is reported for each year modelled from 2020/21 to 2030/31 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.

2017/18 Modelling

For the 2017/18 analysis the modelling follows a similar process to the 2020/21 analysis. The key differences in the modelling steps in A3.1.1 are highlighted below.

1. The first auction simulated is for delivery in 2017/18.

3. There is no previously contracted capacity for 2017/18.

9. Although the model assumes that auction is run in all subsequent years only the results for 2017/18 from this analysis have been used in this report.

2018/19 Modelling

For the 2018/19 analysis the modelling follows a similar process to the 2020/21 analysis. The key differences in the modelling steps in A3.1.1 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 consistent with the de-rating factors used in the 2019/20 T-4 auction and a range of static flow sensitivities similar to those used in the Contingency Balancing Reserve (CBR) analysis.

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

A.3.2 Treatment of Generation Technologies

The DDM models a range of generation technology types. For this analysis they are the same categories which were modelled in the EMR Delivery Plan. Most of these technologies are assumed to either be eligible for the Capacity Market or not. Hydro capacity 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 1.6 GW to 2.0 GW in the period to 2020/21 depending on the FES scenario and year.

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

Table 31: 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	✓	
Dedicated Biomass[33]	✓	
EfW	✓	
EfW CHP		✓
Gas CCS		✓
Gas Turbine	✓	
Geothermal		✓
Geothermal CHP		✓
Hydro	✓	✓
Landfill		✓
OCGT	✓	
Oil	✓	
Storage technologies (e.g. pumped storage)	✓	
Sewage Gas		✓
Solar PV		✓
Tidal		✓
Wave		✓

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

A.4 Least Worst Regret

A.4.1 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 DECC'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. 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 DECC 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)[34] to choose between potential transmission network reinforcement options. This approach has also been used to assess the volume required for National Grid's Contingency Balancing Reserve[35] 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 cots are used; VoLL (Value of Lost Load) = £17,000/MWh as the unit cost of Expected Energy Unserved (EEU) and £49/kW/year[36] as the unit cost of de-rated capacity.

[34] See http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Network-Options-Assessment/
[35] See http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/
[36] 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.

A.4.2 Worked Example

Below is a worked example, taken from the 2017/18 analysis (see Chapter 6 for details of the scenarios and sensitivities modelled in this year). As discussed in Section 2.6.1 academic work on LWR highlighted that sensitivities at the extreme ends of range determine the answer from the LWR calculation. For this reason and to simplify the example without changing the result, we have shown the calculations based on the two extreme sensitivities (denoted by BC_WARM and BC_NON_DEL_2800), the sensitivity that set the recommendation (denoted by BC_COLD) together with the base case (BC) for reference purposes.

1. The capacities required for each case to meet the Reliability Standard are shown with their assumed capacity costs below:

Table 32: De-Rated Capacity requirement for 3 hours LOLE[37]

Case	Capacity required (de-rated) GW	Capacity cost £m
BC_WARM	51.0	2,499
BC	52.8	2,587
BC_COLD	53.8	2,636
BC_NON_DEL_2800	55.6	2,724

2. The EEU and cost of EEU for each case depend on the capacity secured. The following tables show EEU and EEU cost[38] by case for each potential capacity level.

[37] For reasons described in Section 2.6.3, all capacity to secure figures in this report are quoted to the nearest 0.1 GW (100 MW).
[38] Assumes VoLL (Value of Lost Load) = £17,000/MWh as the unit cost of EEU. EEU cost shown to nearest £m

Table 33: EEU (MWh) by capacity level

Case	51.0 GW	52.8 GW	53.8 GW	55.6 GW
BC_WARM	3,450	611	213	26
BC	13,826	3,767	1,634	302
BC_COLD	26,521	8,208	4,025	881
BC_NON_DEL_2800	80,207	27,237	13,826	3,767

Table 34: Cost (£m) of EEU by capacity level

Scenario	51.0 GW	52.8 GW	53.8 GW	55.6 GW
BC_WARM	59	10	4	0
BC	235	64	28	5
BC_COLD	451	140	68	15
BC_NON_DEL_2800	1,364	463	235	64

3. The table below shows the total cost, being the addition of cost of capacity secured and the cost of EEU:

Table 35: Total cost by capacity level (£m)

Scenario	51.0 GW	52.8 GW	53.8 GW	55.6 GW
BC_WARM	2,558	2,598	2,640	2,725
BC	2,734	2,651	2,664	2,730
BC_COLD	2,950	2,727	2,705	2,739
BC_NON_DEL_2800	3,863	3,050	2,871	2,788

4. The Base cost (cost of securing the actual scenario) is subtracted from the above costs to give the absolute regret cost. The following table shows this:

Table 36: Regret cost by capacity level (£m)

Scenario	Base Cost £m	51.0 GW	52.8 GW	53.8 GW	55.6 GW
BC_WARM	2,558	0	40	82	167
BC	2,651	83	0	13	78
BC_COLD	2,705	245	22	0	35
BC_NON_DEL_2800	2,788	1,074	262	83	0

5. The maximum (worst) regret cost is calculated for each capacity level. The table below shows this

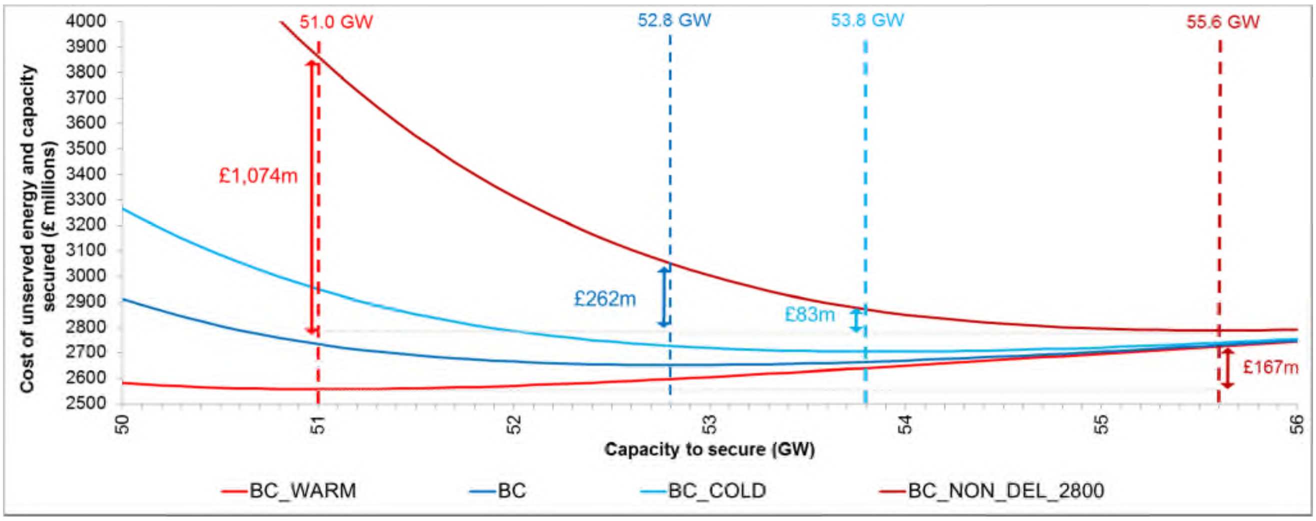
Table 37: Maximum regret cost by capacity level (£m)

Scenario	51.0 GW	52.8 GW	53.8 GW	55.6 GW
Maximum Regret	1,074	262	83	167

6. The minimum (least) of the maximum (worst) regret costs is £83m for the 53.8 GW capacity level associated with the BC_COLD sensitivity.

The following chart of total cost against capacity to secure for the four cases shows costs falling steeply as energy unserved falls but once there is sufficient capacity 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 case is around the bottom of the total cost curve for that case. The maximum regret cost for the four potential capacity levels are also shown on the chart.

Figure 38: Total Cost and Maximum Regret Cost by Capacity Level



Note that the capacity costs associated with the supply curve in the auction are likely to rise in a non-linear way reflecting the increase in unit capacity costs along the supply curve.

The chart also illustrates how the sensitivities at the end of the range influence the regret costs for each potential capacity level and therefore determine the outcome of the LWR calculation.

A.4.3 Capacity to Secure Charts

The charts below for 2020/21, 2017/18 and 2018/19 show how the total cost varies for different potential levels of capacity secured for the scenarios as well as sensitivities at the extreme ends of the potential capacity requirement range.

Figure 39: Cost v Potential Capacity to Secure Levels 2020/21

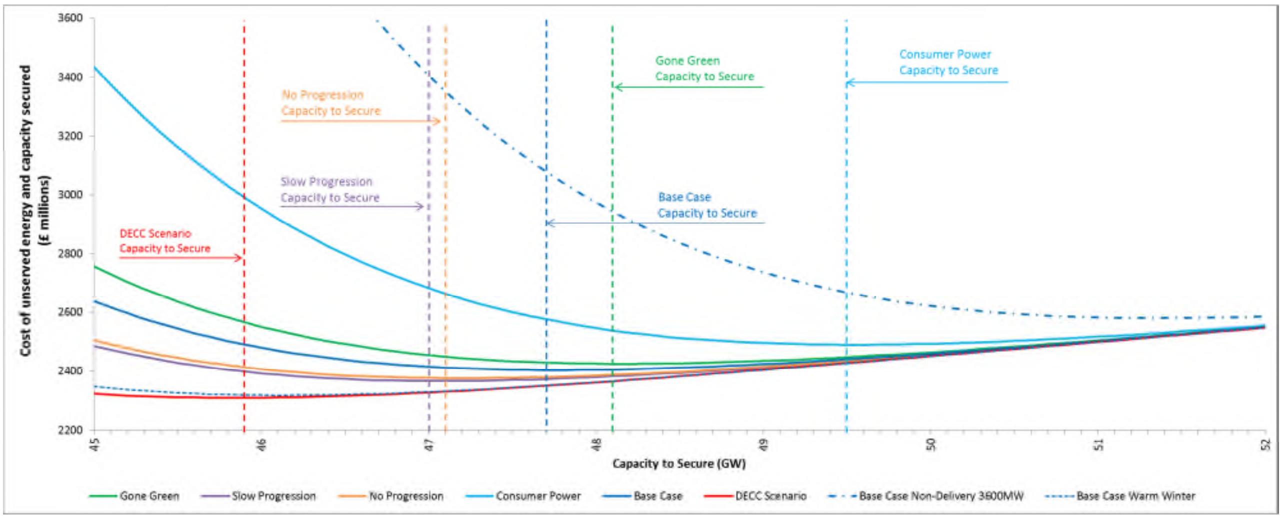


Figure 40: Cost v Potential Capacity to Secure Levels 2017/18

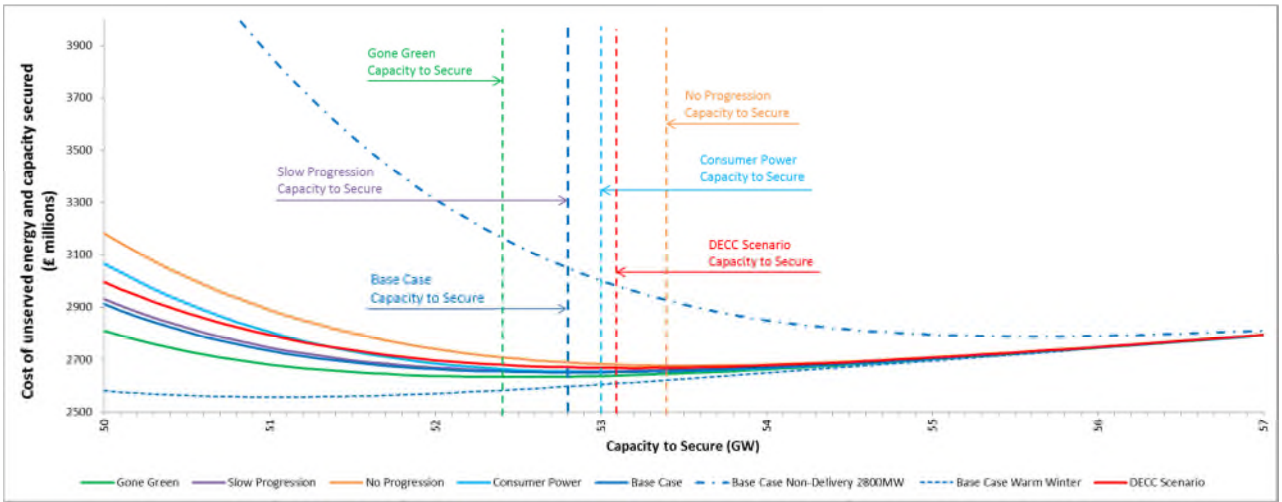
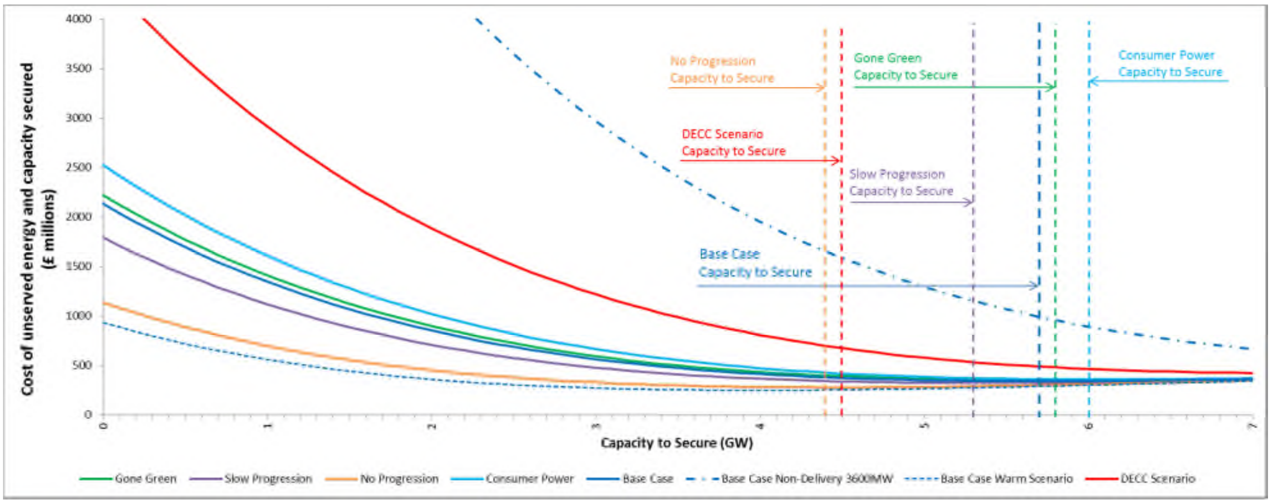


Figure 41: Cost v Potential Capacity to Secure Levels 2018/19

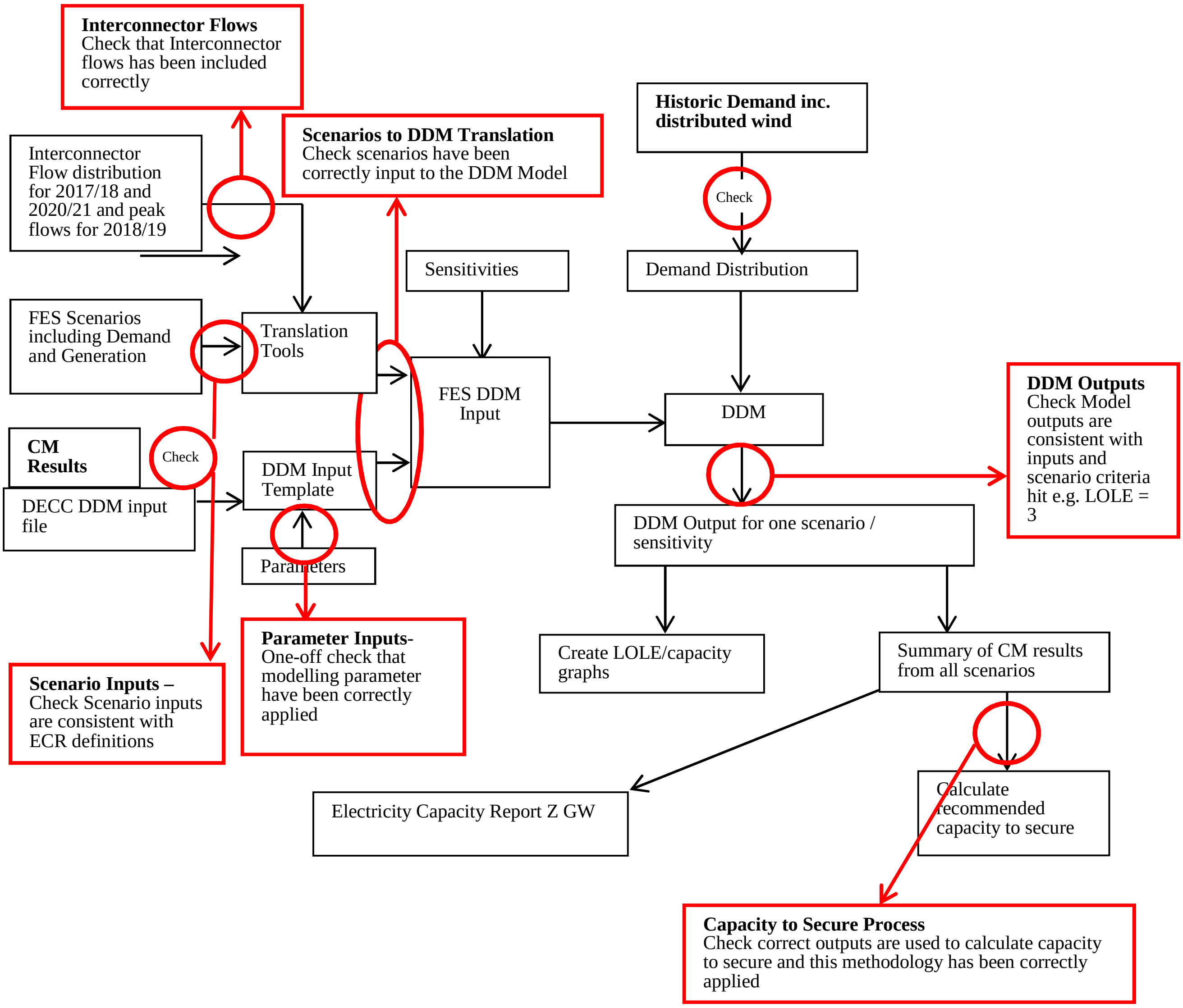


A.5 Quality Assurance

When under taking any analysis National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid have worked closely with DECC's Modelling Integrity team to ensure that the QA process closely aligned to DECC's in house QA process[39]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have a 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 42: QA checks process diagram for each target year



[39] 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 flows assumption/distribution have been discussed with DECC, PTE and Ofgem at various bilateral meetings. We have also consulted the results with the industry at various stakeholder events. For each scenarios, the modelled interconnector flows and results are checked throughout the QA checklist process.

Scenario Inputs

The FES process is driven by extensive stakeholder engagement[40], 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 5th 2016.

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 two analysts to ensure that they are correct and then a final template is created (with a backup) which all

[40] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Engagement/

runs are then based on. This step also includes checking of the inputs like historic 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 DECC 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 DECC 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 DECC 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 DECC

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 Clarke Peacock (LCP[41]), 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 concludes that National Grid is using the model correctly and correctly interpreting the output results.

[41] 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 with final sign off by the Chief Executive.

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National Grid plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

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