nationalgridESO

# National Grid ESO
# Electricity Capacity Report

31 May 2020

(submitted to Department for Business, Energy and Industrial Strategy)

Results from the work undertaken by National Grid ESO for BEIS to recommend the capacity to secure through the Capacity Market.

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# National Grid ESO Electricity Capacity Report


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# 1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling undertaken by National Grid ESO 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 (CM) auctions for delivery in 2021/22 and 2024/25.

The Government requires National Grid ESO to provide it with a recommendation for each auction year based on the analysis of credible scenarios and sensitivities to ensure its policy objectives are achieved.

National Grid ESO has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2019 process. This led to National Grid ESO undertaking steps to improve this year's analysis. In addition, there has been continued engagement with Department for Business, Energy and Industrial Strategy (BEIS), PTE and Office of Gas and Electricity Markets (Ofgem) throughout the year to enable them to scrutinise the modelling approach and assumptions used.

Chapter 2 of this report describes the modelling approach, including the tools used and enhancements made for this year's analysis. Chapter 3 covers the scenarios and sensitivities modelled. Chapter 4 details the de-rating factors for generating technologies, storage, demand-side response (DSR) and interconnected countries. Chapter 5 and Chapter 6 contain modelling results and the recommended capacity to secure for the 2021/22 T-1 and 2024/25 T-4 auctions, respectively. Finally, the Annex contains further details on the assumptions and methods that underpin our recommendations as well as a summary of our previous ECR recommendations and auction outcomes to-date.

The demand and supply assumptions used to inform our recommendations do not consider any potential impact from the COVID-19 pandemic. This is because our assumptions had already been largely finalised when the potential impact from the pandemic arose and even if we had been able to revise them, this would not have been based on any robust evidence as we were still in the early stages of the pandemic. At this stage, we are unable to say how the impact from the COVID-19 pandemic will change our view of supply and demand over the next few years, but we recognise that there could be a material impact on our recommendations. The peak demand forecasts are an example of an assumption that has a material impact on our recommendation and is particularly uncertain due to the link with economic growth.

National Grid ESO is intending to review how the impact of the COVID-19 pandemic could change our supply and demand assumptions as better information becomes available in the coming months. This information could, for example, include revised economic growth forecasts or market intelligence on projections for deployment of new capacity. While we are not intending to carry out the full Future Energy Scenarios (FES) process again to create new supply and demand assumptions, any new information may be used to provide amendments to our existing assumptions.

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

[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816012/Panel_of_Technical_Experts_report_2019.pdf

We have an opportunity to reflect any new information that may impact our ECR recommendations when we undertake the Adjustment to the Demand Curve after prequalification. This is already established in the Capacity Market process[3]. Any revisions to our supply and demand assumptions will be discussed with BEIS, Ofgem and the PTE by September 2020. This will allow time for scrutiny ahead of applying any potential adjustments to our ECR recommendations. It's possible that we may not have all the necessary information we would like to have to robustly assess the impact from COVID-19 – in fact, it is highly likely that we will not. Considering this, we will need to agree with BEIS, Ofgem and the PTE on the appropriateness of making any adjustments to our ECR recommendations. Should any adjustments be made, we will provide details relating to the changes of our supply and demand assumptions in the published Adjustment to the Demand Curve report. This will also include the reasons behind any changes.

While the UK left the European Union (EU) on 31st January 2020, there is still significant uncertainty on the nature of our future relationship with the EU and how close future market arrangements are to the ones that we have experienced under the UK's participation in the Internal Energy Market (IEM). Our assumptions in the Base Case and FES broadly assume a system is put in place that closely resembles the arrangements under the IEM. This, for example, means that we assume there are no additional barriers to interconnector flows. We also assume that the total GB carbon price includes a component that continues on a similar trajectory to the EU Emissions Trading Scheme. However, we have assumed that the current political uncertainty means that there are no new interconnectors in our Base Case by 2024/25 apart from those that have either already started construction or taken a final investment decision. These details are described in Chapter 3.

## 1.1 Results and Recommendations

Table 1 shows National Grid ESO's recommendations for the target capacity for the 2021/22 T-1 and 2024/25 T-4 auctions. Some adjustments may be required to set the final target capacity for each auction following prequalification, which are described in Chapters 5 and 6. While these are our recommendations, the decisions on whether to run an auction and on the final target capacity rest with the Secretary of State. The final target capacity will be published in the Final Auction Guidelines after prequalification.

**Table 1: Recommendations for the target capacity for the 2021/22 T-1 and 2024/25 T-4 Capacity Market auctions**

| | 2021/22 T-1 | 2024/25 T-4 |
|---|---|---|
| Recommended target capacity | 0 GW | 41.6 GW |

Our recommendations are based on assessing the capacity required to meet the Reliability Standard of 3 hours loss of load expectation (LOLE) across a credible range of scenarios. Our modelling assumes that the Base Case and FES cover uncertainty in future electricity demand and supply. This includes uncertainty in peak demand, DSR, generation, storage and interconnection capacity.

[3] For example, the 2023/24 T-4 report was published in February 2020 and can be found here: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/2019%20CM%20Update%20to%20Demand%20Curve%20T-4%202023-24_final.pdf

The scenarios we have modelled are listed as follows:

- Base Case* (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Steady Progression (SP)

*based on the FES Five Year Forecast to 2024/25, then aligned to System Transformation from 2025/26 onwards to provide a full 15-year view

We also model sensitivities to assess uncertainty that is not covered by the scenarios. The sensitivities cover uncertainty in non-delivery, over delivery, station availability, weather, wind output and peak demand. Sensitivities are only applied to the Base Case. Each of the sensitivities is considered credible in that it is either evidence-based (i.e. it has occurred in recent history) or it addresses statistical uncertainty caused by the small sample sizes used for some of the input variables. Section 3.10 describes each sensitivity and how it has been modelled.

The recommendation on the target capacity to secure is informed by a cost-optimised methodology called Least Worst Regret (LWR). The LWR methodology seeks to balance the costs of securing capacity against the costs of unserved energy. The cost assumptions used in the LWR calculation are unchanged from previous ECR analysis. We assume a cost of capacity of £49/kW/year net CONE (Cost of New Entry) and an energy unserved cost (referred to as the Value of Lost Load or VoLL) of £17,000/MWh.[4] Our recommendations for the target capacity correspond to the value on the CM demand curve equal to net CONE. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity.

### 1.1.1 2021/22 T-1 Auction Results

The outcome of the LWR calculation results in a capacity to secure for the 2021/22 T-1 auction of -1.2 GW. As this is a negative target capacity, we recommend a target of **0 GW**.

In general, when compared to the analysis for 2021/22 in the 2017 ECR that ultimately led to the 0.4 GW set aside by the Secretary of State for the T-1 auction, the 2020 ECR LWR outcome for 2021/22 is 1.6 GW lower than the 0.4 GW set aside. This net difference is the result of 5.6 GW of increases offset by 7.2 GW of decreases since the 2017 ECR.

The increases result from: non-delivery (units in the 2017 Base Case awarded agreements in the 2018/19, 2019/20, 2020/21 and 2021/22 T-4 auctions covering 2021/22 that are now known not to be able to honour their agreements); revised de-rating factors for duration-limited storage contracted from the 2020/21 T-4 auction onwards; the interconnection Equivalent Firm Capacity (EFC) being lower than the previously contracted interconnection capacity; the contracted capacity from previous T-4 auctions being greater than the de-rated TEC; higher reserve for largest infeed loss and lower levels of assumed opted-out or

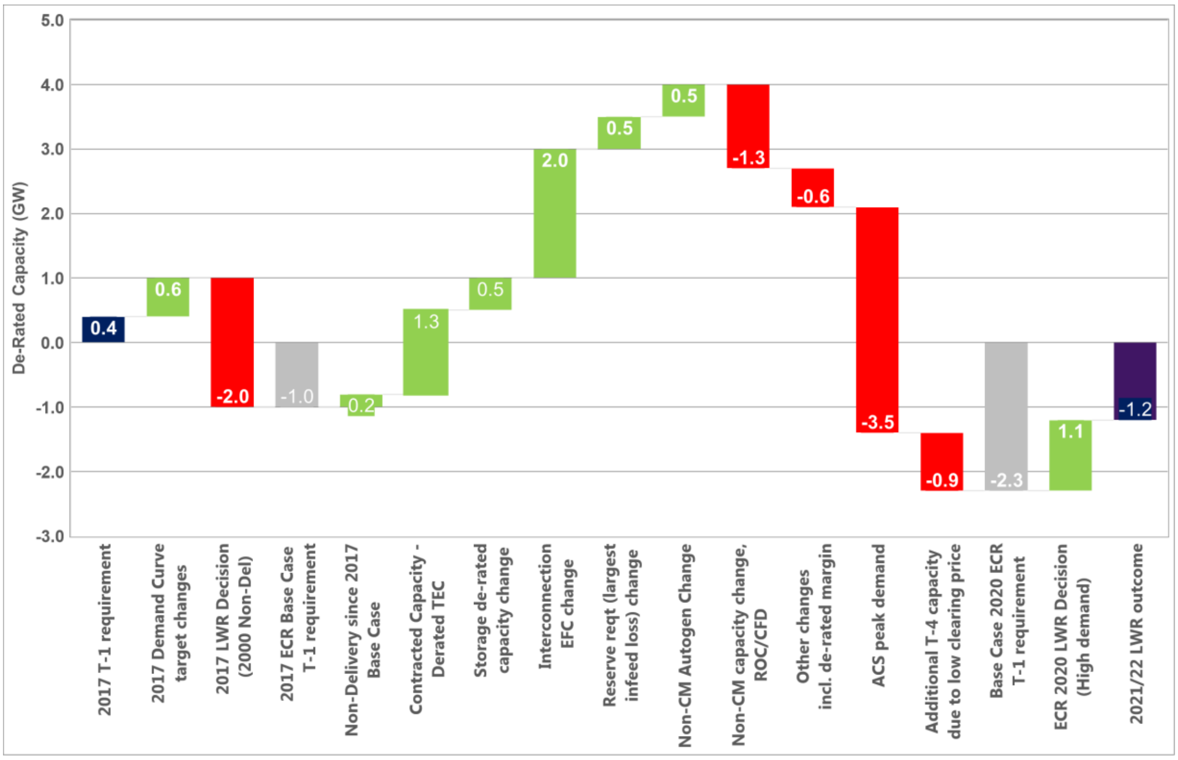
[4] Note that the Government's Reliability Standard was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT). For more information, see: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

ineligible autogeneration than the 2017 Base Case. In addition, the demand curve adjustments made in 2017 following prequalification for the T-4 auction (see Section 5.3.3 for more details) are no longer relevant for the T-1 auction as prequalification for the T-1 auction has not yet taken place and the 2020 Base Case generation assumptions are different to the 2017 Base Case assumptions.

The decreases arise from: a change in the scenarios and sensitivities modelled resulting in a different LWR outcome than in 2017; a reduction resulting from higher non-CM renewable capacity; a lower peak demand for 2021/22 (see Section 5.3.3 for more details); a reduction due to over-securing in the 2021/22 T-4 auction and a net reduction due to other changes.

Figure 1 shows how the original 0.4 GW set aside for the 2021/21 T-4 auction (derived from the 2000 MW non-delivery sensitivity) has changed into a LWR outcome of -1.2 GW (derived from the 2020 Base Case high demand sensitivity) as a result of the net decrease described above.

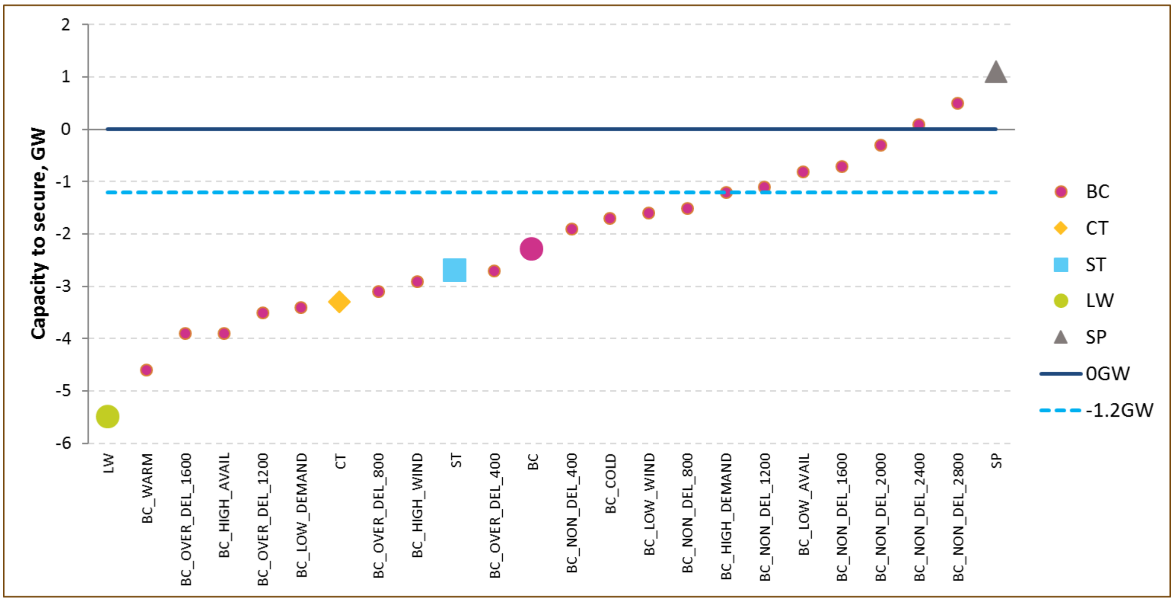
**Figure 1: Comparison with original 2021/22 T-1 requirement (de-rated)**




*Note: intermediate totals in grey above show requirements for 2017 Base Case and 2020 Base Case*

Figure 2 shows the capacity to secure from each of the scenarios and sensitivities modelled. It also highlights the outcome from the LWR (-1.2 GW) and our recommendation (0 GW).

**Figure 2: Least Worst Regret outcome and recommended capacity to secure compared to individual scenario / sensitivity runs – 2021/22**




## 1.1.2 2024/25 T-4 Auction Results

The outcome of the LWR calculation results in a capacity to secure for the 2024/25 T-4 auction of **41.6 GW** derived from the requirement of the nearest Base Case sensitivity (800 MW non-delivery) to the value selected by the LWR tool. Our recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also accounts for any capacity already secured for 2024/25 in earlier T-4 auctions that is assumed in the Base Case.

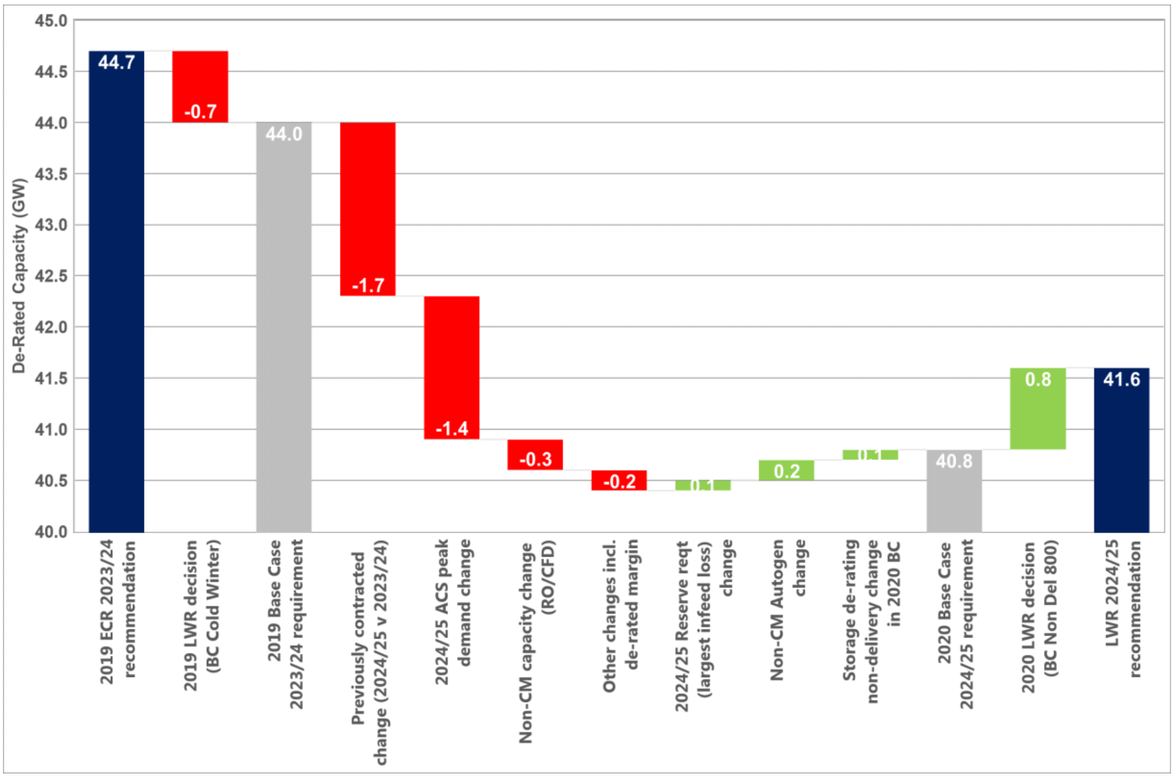
When compared to the analysis for 2023/24 in the 2019 ECR, the 2020 ECR recommendation for 2024/25 is 3.1 GW lower. This net difference is the result of 0.5 GW of increases offset by 3.6 GW of decreases since the 2019 ECR.

The increases result from: lower assumed opted-out or ineligible autogeneration; a change to the FES scenarios resulting in a slightly different LWR outcome; a small increase in reserve for largest infeed loss and a small change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards.

The decreases arise from: an increase in previously contracted capacity from CM units awarded multi-year agreements in recent auctions; a lower peak demand for 2024/25 than for 2023/24 in the 2019 ECR (see Section 3.3 for more details); higher non-CM renewable capacity, and a small net decrease due to other changes.

The waterfall chart in Figure 3, shows how the original 44.7 GW requirement for the 2023/24 T-4 auction (derived from the 2019 Base Case cold winter sensitivity) has changed into a recommendation of 41.6 GW (derived from the 2020 Base Case 800 MW non-delivery demand sensitivity) as a result of the 3.1 GW net reduction described above.

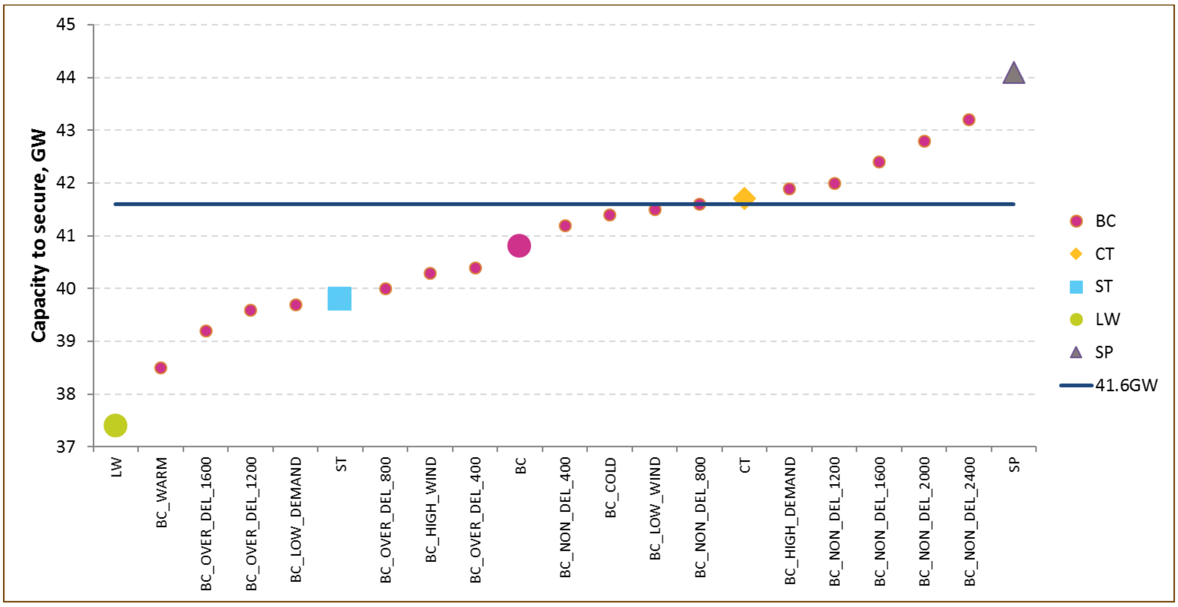
**Figure 3: Comparison with recommended 2023/24 T-4 requirement in 2019 ECR**




*Note: intermediate totals in grey above show requirements for 2019 Base Case and 2020 Base Case*

Figure 4 shows the capacity to secure from each of the scenarios and sensitivities modelled. It also highlights the outcome from the LWR (41.6 GW).

**Figure 4: Least Worst Regret recommended capacity to secure compared to individual scenario / sensitivity runs – 2024/25**



## 1.2 Interconnected Countries De-rating Factor Ranges

This year we have made changes to our modelling approach to determine de-rating factor ranges for interconnected countries. For the first time, we shared details of our proposals ahead of carrying out our ECR analysis. While we requested feedback to be sent directly to the PTE, several respondents also provided a copy of their feedback to us. We are highly appreciative of the feedback, particularly recognising the short timescales. We found it constructive and helpful for us to reflect on. There were several areas raised (e.g. around the use of historical data, model validation, consistency with other European adequacy studies, sensitivities to model) that could be considered for future development projects in this area. A theme from the responses was a desire for greater information and transparency on this, and we are committed to engaging further on this to help market participants better understand and challenge our modelling. With this in mind, we are intending to provide further information, most likely via an industry webinar by the end of July once the ECR has been published.

Table 2 shows the de-rating factor ranges for interconnected countries based on the modelling we have done using our pan-European market model, BID3. These cover existing and potential future interconnected countries. These ranges inform the choice of de-rating factors for the 2021/22 T-1 and 2024/25 T-4 auctions. Following on from last year's ECR, the requirement for a historical 'floor' to constrain de-rating factors does not apply.

In this year's modelling we have revised how we can better account for the contribution interconnectors make to security of supply during times of system stress. This means that the stress periods used in the interconnector analysis are now more consistent with the definition in the Capacity Market rules. It also means that the methodology for interconnectors is better aligned with other technologies such as storage and renewables. Further details on our modelling approach are described in Section 4.2. Our revised approach is also more consistent with work being undertaken by ENTSO-E to develop a consistent methodology to determine the maximum level of cross-border capacity that can participate in capacity mechanisms. This work is being undertaken as part of the Clean Energy Package (Article 26 of Regulation (EU) 2019/943). Further details can be found on ENTSO-E's website.[5]

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain. This assumes that this is more appropriately allowed for in the adjustments made to individual interconnector de-rating factors along with technical availability.

[5] https://consultations.entsoe.eu/markets/proposal-for-cross-border-participation-in-capacit/consult_view/

**Table 2: Modelled de-rating factor ranges for interconnected countries. De-rating factors from the 2019 ECR are shown for comparison**

| Country | ECR 2019 2020/21 T-1 | | ECR 2019 2022/23 T-3 | | ECR 2019 2023/24 T-4 | | ECR 2020 2021/22 T-1 | | ECR 2020 2024/25 T-4 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Low | High | Low | High | Low | High | Low | High | Low | High |
| **Belgium** | 75 | 98 | 52 | 65 | 38 | 56 | N/A | N/A | 46 | 88 |
| **Denmark** | N/A | N/A | N/A | N/A | 35 | 35 | N/A | N/A | 45 | 80 |
| **France** | 88 | 99 | 66 | 81 | 57 | 79 | N/A | N/A | 50 | 91 |
| **Germany** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 54 | 83 |
| **Ireland** | N/A | N/A | 30 | 44 | 24 | 32 | 54 | 99 | 24 | 66 |
| **Netherlands** | N/A | N/A | 44 | 55 | 30 | 44 | N/A | N/A | 48 | 84 |
| **Norway** | N/A | N/A | 93 | 99 | 93 | 99 | N/A | N/A | 91 | 100 |

## 1.3 De-rating Factors for Conventional Plants, Storage and Renewables

Tables 3, 4 and 5 show the de-rating factors for conventional plants, storage and renewables, respectively. 2019 de-rating factors are shown for comparison. No changes have been made to the methodology used to determine these de-rating factors. Further details are included in Chapter 4.

National Grid ESO has used the current approach to determine station availabilities and de-rating factors for the last few years. While both formal (e.g. on storage and renewable de-rating factors) and informal (e.g. discussions at industry workshops and bilateral meetings) consultations have been held, it is important that all stakeholders have an opportunity to engage in this process. This will help National Grid ESO understand any concerns that stakeholders may have regarding our approach and help to inform any future changes to the methodologies. Therefore, National Grid ESO continues to welcome comments and questions on our approaches either through email (emrmodelling@nationalgrid.com), industry forums or bilateral meetings. Any changes to de-rating factor methodologies will require consultation with industry.

We would particularly appreciate any feedback on our developing work on constrained hybrid sites (described in Section 2.5.2) and how we calculate de-rating factors for distribution-connected generation (please see Section 4.1 for further information).

**Table 3: De-rating factors for conventional plants. De-rating factors apply to both the 2021/22 T-1 and 2024/25 T-4 auctions.**

| Technology Class | Plant Types Included | ECR 2019 | ECR 2020 |
|---|---|---|---|
| Oil-fired steam generators | Conventional steam generators using fuel oil | 91.26% | 95.22% |
| Open Cycle Gas Turbine (OCGT) | Gas turbines running in open cycle fired mode | 94.98% | 95.22% |
| Reciprocating engines (non-autogen) | Reciprocating engines not used for autogeneration | 94.98% | 95.22% |
| Nuclear | Nuclear plants generating electricity | 81.22% | 81.43% |

| | | | |
|---|---|---|---|
| Hydro (excl. tidal / waves) | Generating Units driven by water, other than such units:<br>a) driven by tidal flows, waves, ocean currents or geothermal sources; or<br>b) which form part of a Storage Facility | 89.65% | 90.99% |
| CCGT | Combined Cycle Gas Turbine plants | 90.00% | 90.00% |
| CHP and autogen (provided by BEIS) | Combined Heat and Power plants (large and small-scale)<br>Autogeneration – including reciprocating engines burning oil or gas | 90.00% | 90.00% |
| Coal | Conventional steam generators using coal | 85.81% | 84.80% |
| Biomass | Conventional steam generators using biomass | 85.81% | 84.80% |
| Energy from Waste | Generation of energy from waste, including generation of energy from:<br>a) conventional steam generators using waste;<br>b) anaerobic digestion;<br>c) pyrolysis; and<br>d) gasification. | 85.81% | 84.80% |
| DSR[6] | | 86.14% | 79.21% |

### Table 4: De-rating factors for duration limited storage.

<table>
<tr><th>Duration (hours)</th><th>ECR 2019 2020/21 T-1</th><th>ECR 2019 2022/23 T-3</th><th>ECR 2019 2023/24 T-4</th><th>ECR 2020 2021/22 T-1</th><th>ECR 2020 2024/25 T-4</th></tr>
<tr><td>0.5</td><td>12.26 %</td><td>10.59 %</td><td>10.21 %</td><td>12.75 %</td><td>12.38 %</td></tr>
<tr><td>1.0</td><td>24.70 %</td><td>21.36 %</td><td>20.43 %</td><td>25.32 %</td><td>24.77 %</td></tr>
<tr><td>1.5</td><td>36.96 %</td><td>31.94 %</td><td>30.83 %</td><td>37.71 %</td><td>36.97 %</td></tr>
<tr><td>2.0</td><td>48.66 %</td><td>42.53 %</td><td>41.04 %</td><td>49.17 %</td><td>48.62 %</td></tr>
<tr><td>2.5</td><td>58.68 %</td><td>52.18 %</td><td>50.51 %</td><td>58.23 %</td><td>58.78 %</td></tr>
<tr><td>3.0</td><td>65.93 %</td><td>59.43 %</td><td>57.94 %</td><td>64.70 %</td><td>66.18 %</td></tr>
<tr><td>3.5</td><td>70.38 %</td><td>64.07 %</td><td>62.77 %</td><td>68.76 %</td><td>70.98 %</td></tr>
<tr><td>4.0</td><td>72.98 %</td><td>67.04 %</td><td>65.93 %</td><td>71.35 %</td><td>73.76 %</td></tr>
<tr><td>4.5</td><td>75.03 %</td><td>69.27 %</td><td>68.16 %</td><td>73.20 %</td><td>75.79 %</td></tr>
<tr><td>5.0</td><td rowspan="2">95.08%</td><td>71.13 %</td><td>70.20 %</td><td rowspan="2">94.64 %</td><td rowspan="2">94.64 %</td></tr>
<tr><td>5.5+</td><td>95.08 %</td><td>95.08 %</td></tr>
</table>

### Table 5: De-rating factors for renewables.

| Technology Class | ECR 2019 2020/21 T-1 | ECR 2019 2022/23 T-3 | ECR 2019 2023/24 T-4 | ECR 2020 2021/22 T-1 | ECR 2020 2024/25 T-4 |
|---|---|---|---|---|---|
| Onshore Wind | 8.98% | 8.20% | 7.42% | 8.01 % | 7.81 % |
| Offshore Wind | 14.45% | 12.30% | 10.55% | 12.11 % | 11.13 % |
| Solar PV | 2.34% | 3.13% | 3.22% | 2.54% | 2.34 % |

[6]Details of the DSR De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf

For storage, the de-ratings for the T-4 year are higher than the de-rating factors for the T-4 year in the 2019 ECR. This is a result of the lower level of storage capacity in the T-4 year in the 2020 ECR Base Case than in the 2019 ECR Base Case (even though the years have advanced by one) with a notable reduction in the shorter duration categories. This reduction reflects updated market information and in particular the storage units awarded capacity market agreements in recent auctions. (see Annex A.6 for a breakdown of the storage capacity assumptions).

# 2. The Modelling Approach

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

## 2.1 High Level Approach

The modelling approach is guided by the policy backdrop and 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)[7]?***

Following consultation with BEIS and the PTE, it was agreed that the Dynamic Dispatch Model (DDM)[8] continues to be an appropriate modelling tool to answer this question. This maintains consistency with the energy market modelling work undertaken by BEIS. The DDM has the functionality to model the Capacity Market and produces the same results as National Grid ESO's capacity assessment model, when given the same inputs.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[9] and a Base Case. The scenarios and Base Case are developed to reflect the credible range of uncertainty in future electricity supply and demand. Further details on the scenarios and Base Case can be found in Chapter 3. The main assumptions in the scenarios and Base Case include:

- **Peak demand** – this is the underlying, unrestricted demand in Great Britain. 'Underlying demand' means that it includes all peak demand in Great Britain, not just that on the transmission system. 'Unrestricted' means that no Demand Side Response (DSR) or Triad avoidance has been subtracted.
- **Generation capacity** – this is the installed capacity of all technologies (including storage) connected to both the transmission and distribution networks.
- **Interconnector capacity** – this is the installed capacity connecting Great Britain to neighbouring markets in Europe. Interconnector flows at peak are calculated in DDM, so this is not an input assumption.

We also apply a set of sensitivities to the Base Case to assess potential uncertainty that is not covered by the scenarios. Further details on these can be found in Section 3.10.

The modelling process is shown in Figure 5. We model a 15-year horizon in the DDM that extends to 2034/35. The modelling process determines both the capacity to secure and the capacity expected to be delivered outside of the Capacity Market for each scenario and sensitivity modelled. The capacity to secure for each of these cases is then considered

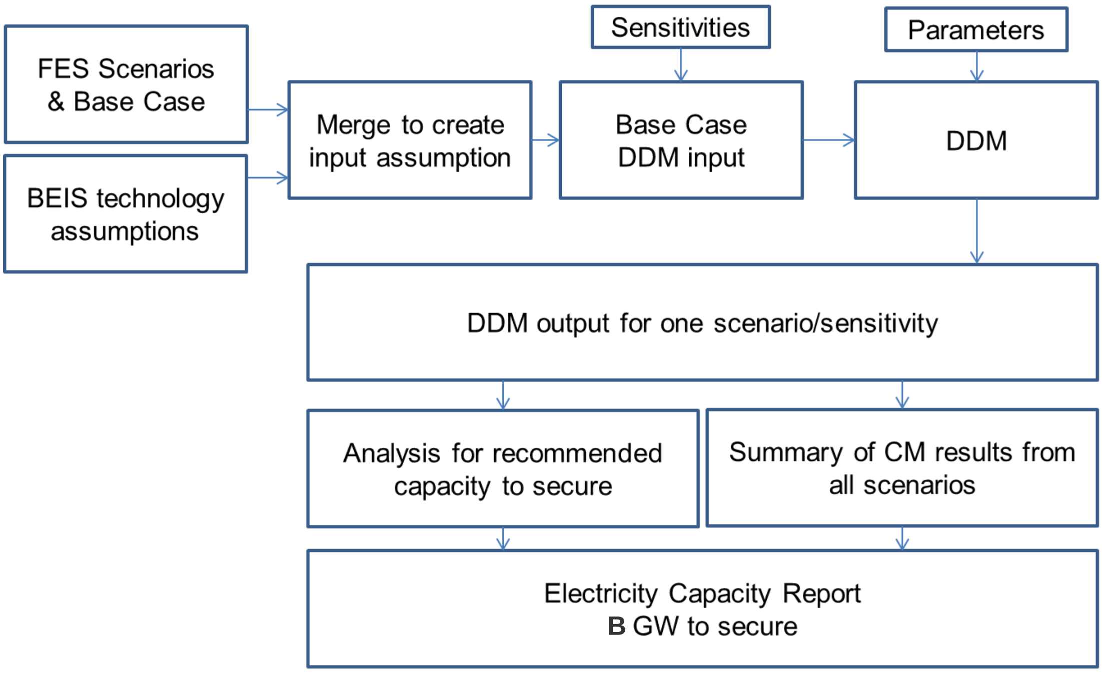
[7] LOLE is the expected number of hours when demand is higher than available generation during the year but before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

[8] DDM Release 6.1.28.1 was used for this analysis

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

together to produce a recommended capacity to secure for the 2021/22 T-1 and 2024/25 T-4 Capacity Market auctions. Further details describing this can be found in Annex A.5.

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




## 2.2 DDM Outputs Used in the ECR

The key outputs from the DDM that are used in the ECR are the aggregate capacity values. These outputs are used for all 15 years that are modelled. Specifically, the outputs include:

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

Note that A = B + C. Further details on the modelling and aggregate capacities can be found in Annex A.4 and A.5.

In addition to the aggregate capacity values, we also use the expected energy unserved (EEU) and LOLE for the potential de-rated capacity levels in the Capacity Market auction years 2021/22 and 2024/25. These values are used in the Least Worst Regret (LWR) calculation to produce the recommended target capacity for each auction. Further details can be found in Chapters 5 and 6.

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

## 2.3 Stakeholder Engagement

National Grid ESO has a well-established and extensive consultation process to produce the FES. This operates on an annual basis and includes a launch conference, webinars, workshops and bilateral meetings. This gives opportunity for our stakeholders to provide feedback on our scenarios and share information on the latest market developments. 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[10] in line with our licence condition. The document, published annually in February, shows how stakeholder feedback influences the framework, scenario framework and assumptions that underpin the scenarios. This document also contains details of topic specific feedback that we have received from stakeholders and how we have taken this forward.

National Grid ESO 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 ESO also engages with stakeholders in its role as EMR Delivery Body. This includes the CM Implementation workshops, meetings with both trade organisations and individual companies as part of our ongoing consultation around the EMR work. Our engagement also includes wider industry consultation on the de-rating factors that we model on behalf of BEIS for use in the auctions (e.g. renewables and duration limited storage).

## 2.4 High Level Modelling Assumptions

In addition to the Base Case and scenario assumptions described in Chapter 3, the DDM also requires some additional modelling assumptions. This section gives an overview of these assumptions relating to:

- Demand and generation
- Interconnectors
- Station availability

### 2.4.1 Demand and Generation

The starting point for the DDM assumptions on demand and generation was the set of assumptions used in the latest BEIS modelling (e.g. includes technology assumptions for generation levelised costs). This forms our DDM input file template. There are several key inputs and assumptions in the DDM input file, which we overwrite with assumptions in the new 2020 FES scenarios, Base Case and the agreed sensitivities. These key assumptions are the ones that have a material impact on the capacity to secure and include:

- Demand Forecasts
  - Peak demand (plus reserve for largest infeed loss)
  - Annual demand
- Generation Capacity
  - Capacity eligible for the Capacity Market

[10] http://fes.nationalgrid.com/media/1457/stakeholder-feedback-document-2020.pdf

    - Capacity outside the Capacity Market (including capacity secured via previous auctions)
    - Capacities of existing and new interconnectors
- Station availabilities by technology

Further detail on these key assumptions is provided in the Annex A.4.

### 2.4.2 Interconnector Assumptions

Interconnector capacities are based on those assumed in the Base Case and scenarios in the FES. This includes details of existing and new interconnectors. Further details on these assumptions is provided in Section 3.9.

In the DDM, we have modelled the contribution of interconnectors to GB at peak times in each scenario and delivery year using a probabilistic distribution of interconnector flows. This assigns probabilities to different import / export levels for a given level of net system margin. These distributions are derived from our own pan–European market modelling in BID3[11]. The DDM calculated an Equivalent Firm Capacity (EFC) for interconnection which was used as an estimate of the aggregate interconnector de-rated capacity. The interconnector distributions in the DDM for the 2020 ECR were based on interconnector flows using FES 2019 assumptions. This was because the method to calculate interconnector de-rating factors has now substantially changed (see Section 4.2) and so the BID3 dispatch modelling to update these distributions was not carried out. However, this had no material impact on our recommendations for either the 2021/22 T-1 or 2024/25 T-4 auctions.

The modelled de-rating factor range for interconnection has no impact on the total de-rated capacity (including interconnection) required to meet the Reliability Standard in the T-4 auction. In the auction, interconnection capacity will compete with other types of new / existing eligible capacity to meet the capacity requirement. However, the interconnector EFC calculated by the DDM could potentially have an impact on the T-1 requirement as modelled in DDM, should the calculated EFC be significantly different to the amount of previously contracted capacity. If this was to occur, and if it was considered to have a material impact on our T-1 recommendation, National Grid ESO would consider whether it was appropriate to make an adjustment in its ECR recommendation and / or adjustment to the Demand Curve after prequalification. While National Grid ESO will continue to enhance our interconnector modelling to minimise any mis-alignment, differences between the EFC calculated in DDM and the previously contracted capacity may be difficult to avoid. Further work on this may be carried out as a development project ahead of next year's ECR.

In addition to this modelling work, National Grid ESO will provide modelled ranges 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 modelled de-rating factors ranges for each country.

[11] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite

### 2.4.3 Station Availabilities and De-rating Factors

This has been split into four groups covering: conventional generation, intermittent renewable generation, duration limited storage and interconnectors.

#### 2.4.3.1 Conventional generation

Breakdowns and maintenance cycles mean that we assume conventional generation is not available to generate all the time. National Grid ESO calculate the expected availability for each generation type based on its performance during the winter peak period over the last seven years[12]. This approach has been used by National Grid ESO in its medium to long term modelling, as well as being used for the EMR Delivery Plan. This methodology is described in detail in the Capacity Market Rules 2.3.5.

#### 2.4.3.2 Intermittent renewable generation

Intermittent renewable plants such as wind and solar are assumed to run whenever they have an available source of fuel (e.g. the wind is blowing or the sun is shining). When considering these plants, National Grid ESO assesses 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 Great Britain, which is converted into wind output generation using technology power curves. These power curves are used in our modelling to determine the expected contribution of wind to security of supply, which is referred to as the wind EFC. The EFC is defined as the level of 100% reliable (firm) plant that could replace the entire wind fleet and provide the same contribution to security of supply.

The wind EFC depends on many factors that affect the distribution of available wind generation. These include the amount of wind capacity installed on the system, its geographical location and the amount of wind generation that might be expected at periods of high demand. It also depends on how tight the overall system is. This is because as the system gets tighter, there will be more periods when wind generation is needed to meet demand (i.e. prevent loss of load) rather than displacing other types of generation in the merit order. Therefore, the wind EFC will be higher if the overall system is tighter. It should be noted that the wind EFC is not an assumption of wind output at peak times and consequently should not be considered as such. The wind EFC values calculated by DDM for the Base Case are included in Annex A.4.4.

Solar PV can make a small contribution to security of supply, particularly if storage capacity is installed. This was evident from a previous development project as reported in the 2019 ECR. A related project also reviewed the de-rating factors used for solar (and storage) in the DDM so that the total (storage + wind + solar) fleet de-rated capacity in the DDM aligned to the combined (storage / wind / solar) fleet EFC calculated in the development project.

[12] Specifically, these periods are 0700-1900 Monday-Friday, December-February (inclusive) on days with a peak demand greater than the 50th percentile (90th percentile for CCGTs) of demand for that winter

The solar fleet EFC in the DDM is calculated this way using updated estimates. Please refer to section 2.5.2 in the 2019 ECR for further details on these projects.[13]

The Government has recently made changes to allow wind and solar (which are not receiving support under low carbon support schemes, including the RO or CfD) to participate in the Capacity Market. The ECR now includes recommended wind and solar de-rating factors to help facilitate this (see Chapter 4). However, it should be noted that there is a difference between the wind and solar fleet EFC used in DDM to set the target capacity and the recommended auction de-rating factors for any subsequent wind and solar. The EFC used in DDM represents the contribution to security of supply from the entire wind and solar fleet. This includes capacity that is non-eligible for the CM. The de-rating factors for any subsequent wind and solar are based on incremental EFCs to reflect the additional contribution to security of supply brought by delivering new projects via the Capacity Market. Please refer to our industry consultation conclusions document[14] for further information.

#### 2.4.3.3 Duration limited storage

The market for battery storage has grown fast with many having won Enhanced Frequency Response (EFR) or Firm Frequency Response (FFR) ancillary service contracts as well as CM contracts. During the second half of 2017 (in line with the first part of recommendation 28 in the 2017 PTE report), we undertook an extensive industry consultation on a proposed methodology for calculating appropriate de-rating factors for duration limited storage. The details of this method which uses an EFC approach can be found in our final report[15]. This method has been re-run for this year's analysis using the updated assumptions for storage capacity and duration in the Base Case (see Annex A.6 for further details).

#### 2.4.3.4 Impact of availability assumptions

Given that the recommended capacity to secure is a de-rated value, the assumptions around availability of both conventional and renewable capacity have limited impact on the recommendation. Broadly the same level of de-rated capacity is required to hit the 3 hours LOLE target, although, the name-plate capacity required to achieve that level of de-rated capacity will be slightly different.

## 2.5 Development projects

Development projects are undertaken each year to enhance the modelling in the ECR. The development projects are intended to address feedback from the PTE provided as recommendations in their annual report and any other concerns where the modelling could be improved. The development projects taken forward each year are selected from a prioritisation process involving National Grid ESO, BEIS, the PTE and Ofgem. National Grid ESO then deliver the development projects between September and February, which includes regular engagement with BEIS, Ofgem and the PTE, who consider whether the

[13] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf
[14] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf
[15] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

outputs of the projects have been delivered and are appropriate to be included in the ECR modelling.

### 2.5.1 Process for selecting which development projects to progress

The prioritisation for the 2019/20 development projects followed the same process as last year. Each project was ranked independently by National Grid ESO, BEIS, Ofgem and the PTE considering factors such as its potential impact on our recommendations, the effort required and how urgent it was deemed to be. The prioritisation process also considers the potential complexity of the project and whether sufficient data is available to deliver the intended output. Scoring across these formats were totalled to give ranking to each project. All rankings were then combined to give a single prioritised list reflecting the views of all four parties. The highest priority projects are then taken forward.

### 2.5.2 Key projects undertaken

In their 2019 report[16], the PTE made ten new recommendations numbered 42 to 51, each of which was considered as a potential development project alongside others for prioritisation. Three of the new PTE recommendations were not progressed at all. These were recommendations 44, 49 and 50. This was mainly due to a combination of not having access to reliable data to undertake the analysis and that they were considered to have a lower impact on our recommendations than other projects taken forward. While recommendation 42 was not taken forward this year, as this had been partly covered by a previous development project and so was considered less urgent than other projects taken forward. These recommendations will remain on the prioritisation list for next year and may be progressed further then. Annex A.3 contains a list of all the development projects considered and which ones were progressed based on the prioritisation scoring.

A summary of the key development projects taken forward this year is included below.

#### Demand forecasting bias

In response to recommendation 43 in the 2019 PTE Report, National Grid ESO took steps to demonstrate that there was not a systematic bias of over-forecasting. This was presented to the PTE in September 2019. Key points included that the over forecasting in demand has been reducing over time since the introduction of the demand forecast incentive in April 2016 as we have made annual improvements. Also, there was a step change in the 2019 forecast which reduced the T-1 forecast by 1.3GW: we believe this removes any perceived bias in the forecast. These arguments were accepted by the PTE and the outcome was reported to the market in the Adjustments to the Demand Curve for the 2022/23 T-3[17] and 2023/24 T-4[18] auctions published in January 2020. Further work was set out to understand

[16] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816012/Panel_of_Technical_Experts_report_2019.pdf

[17] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Report%20to%20SoS%20regarding%20update%20to%20demand%20curve%20T-3%202022-23.pdf

[18] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Report%20to%20SoS%20regarding%20update%20to%20demand%20curve%20T-4%202023-24.pdf

the uncertainty of forecasting demands and more detailed analysis of the different elements and timescales of the forecasts. In this year's ECR we have included some additional information in Annex A.1 on our demand forecasting performance to provide greater transparency: this shows that for the most recent two winters there has been an under-forecast of restricted national peak demand. In addition, the letter written to Ofgem under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[19] and the steps taken to taken to improve the peak demand forecast.

## Assessment of availabilities for ageing generation

In response to recommendation 45 in the 2019 PTE Report, National Grid ESO carried out new analysis of conventional plant availability to better understand the drivers, including the impact of an ageing fleet. The analysis focussed on nuclear, coal and gas generation and considered factors such as the appropriate amount of history to include in the assessment (we currently use seven years); any specific trends linked to years with high / low fleet availability; assessment of individual stations, including ones that have already closed. We also considered whether any appropriate data or methods could be identified to assess future availability without extrapolating historical trends.

In the absence of any robust forward-looking indicators for plant availability, National Grid ESO concluded that evidence based on historical performance remains appropriate. Assessment of the historical data supported that the current approach remains appropriate with the data that is currently available, and so no changes were proposed. It may be appropriate to revisit this again in a future development project should alternative data, information or modelling approaches be identified.

## Black Swan events and combined sensitivities

In response to recommendation 46 in the 2019 PTE Report, National Grid ESO revisited work undertaken in the 2017 ECR to assess the impact of including more extreme sensitivities in our modelling. Such cases could include potential Black Swan events or combinations of sensitivities.

One of the challenges of including such cases in our modelling is that they would inevitably be expected to have a lower probability of occurrence, yet they would carry equal weighting in the Least Worst Regret (LWR) calculation. In the 2017 ECR, National Grid ESO described a potential hybrid LWR approach proposed by our academic consultants.[20] This approach accounted for the lower probability of the extreme sensitivities by considering them as a separate set to the core sensitivities.

This development project revisited this approach and considered the potential impact of over- and non-delivery of around 5 – 6 GW[21], with assumed probabilities of around 0.01 -

[19] To be published at the same time as the ECR at https://www.emrdeliverybody.com/cm/home.aspx
The letter published in 2019 is available at
https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Demand%20Incentive%20Letter%202019.pdf

[20] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

[21] For example, 6 GW CCGT experienced unplanned outages during the 'Beast from the East' weather event in late February / early March 2018, which was a rare cold, windy period. As an example of over-delivery, at the start of winter 2019/20, around 5 GW of CM-eligible capacity was assumed to be available without a CM agreement.

0.015[22]. The level of over- and non-delivery was chosen to reflect a plausible but less likely upper limit. The analysis concluded that in order for such cases to have an impact on the recommended capacity to secure, they would need to be either (a) more extreme in terms of the level of over- or non-delivery or (b) have a probability similar to the sensitivities in the core set. Neither of which was considered credible. A similar conclusion was reached in the 2017 analysis demonstrating the robustness of the approach.

### Creation of an embedded capacity register

In response to recommendations 47 and 48 in the 2019 PTE Report, National Grid ESO have supported a Distribution Connection and Use of System Agreement (DCUSA) Change Proposal referred to as DCP350.[23] We have taken an active role in the Working Group and the Change Proposal which has now been approved by DCUSA Parties recommending that Ofgem now accept the proposal.[24] This will lead to better data quality that will help us improve our modelling for embedded generation. Assuming DCP350 is approved, we expect the improved data to be available in July 2020 following Ofgem accepting the proposal. This would then enable a 2020/21 development project to improve our embedded generation modelling to be progressed.

### Co-location / hybrid de-rating factor method

In response to recommendation 51 in the 2019 PTE Report, National Grid ESO has carried out work to enhance our modelling capability which is required to determine de-rating factors for co-located / hybrid sites. The existing approach de-rates each component in a hybrid site separately, in line with the approaches described in Section 2.4.3. This approach is fine if the sum of the de-rated components is equal to or below the site entry capacity. However, if the site entry capacity is such that it is lower than the sum of the de-rated components, then an alternative approach may be required as the site will not be able to meet its capacity obligation if it secures a CM agreement.

This is a complex task and would likely be delivered in phases over two or three years. This first phase sought to develop our modelling capability such that we could better assess such sites and help us prepare to implement a new approach if / when it is considered necessary. Any changes to the de-rating factor methodology will be subject to industry consultation and no changes have yet been made.

In this project, we worked closely with Lane Clark & Peacock LLP (LCP) to develop additional functionality in their Unserved Energy Model (UEM), which is currently used to determine de-rating factors for duration limited storage and renewables. The approach considered different combinations of three broad categories of hybrid site components: conventional generation, intermittent renewables and duration limited storage.

The modelling functionality has been developed to ensure that the results for unconstrained sites are consistent with our existing modelling in the UEM. This means that the components are considered separately, with independent plant outages, wind / solar data and storage algorithm applied appropriately. For constrained sites, a priority is applied to

[22] In this analysis, we assumed the sensitivities in the core set have a probability of around 0.05 (i.e. around 20 sensitivities with an equal probability)

[23] https://www.dcusa.co.uk/group/dcp-350-working-group/

[24] See update published on 5 May 2020 at: https://www.dcusa.co.uk/group/dcp-350-working-group/

the site such that intermittent components are used first, then conventional followed by storage. A cap is applied to ensure the total output cannot exceed the site entry capacity. The UEM can calculate both the incremental and average EFC for the hybrid site, similar to our existing method for storage and renewables, which can use either LOLE or EEU as the risk metric. The new functionality has been tested for different combinations of components on hybrid sites.

Exploratory analysis carried out as part of this project on a sample of typical hybrid sites, suggested that the current approach of separately de-rating the component technologies included in a hybrid site is likely to be robust for most such sites. However, if evidence emerges of constrained hybrid sites for which this is not the case, a future second or third phase of this project could be progressed, which may lead to a new de-rating factor methodology for constrained hybrid sites.

### Modelling interconnector flows at times of system stress

While this was not a PTE recommendation, this project built on the improvements made to our modelling for interconnector de-rating factors in the 2019 ECR. This project has led to further enhancements in our interconnector modelling, most notably:

1. How we use stress periods in the analysis
2. Better modelling of interconnector flows during stress periods

Further details on these changes are described in Section 4.2.

## 2.6 Modelling Enhancements since Last Report

Section 2.5 describes several development projects carried out in response to BEIS, Ofgem and National Grid ESO's ideas along with the recommendations from the PTE. While these developments have not led to any material changes to the DDM functionality for the 2020 ECR, we have adopted a newer DDM version for our modelling this year. The 2020 ECR modelling has used DDM version 6.1.28.1.

## 2.7 National Grid ESO Analysis Delivery Timeline 2020

The process and modelling analysis have been undertaken by National Grid ESO. We have also engaged with BEIS, Ofgem and the PTE throughout the process to ensure that our work can be appropriately scrutinised.

The work was carried out between September 2019 and May 2020 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 interconnected countries, conventional, storage and intermittent renewables technologies for use in the auctions.

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

- Development plan produced in September 2019

- Development projects phase October 2019 to February 2020
- Production plan developed in February 2020
- ECR modelling March to May 2020
- National Grid ESO's ECR sent to BEIS before 1st June 2020
- Publication of ECR in line with BEIS publishing auction parameters in July 2020

## 2.8 Quality Assurance

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

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

1. **Interconnector flows** – Check the interconnector flow distribution
2. **Scenario inputs** – Check the model input assumptions
3. **Parameter Inputs / CM Results / Historic Demand 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

The PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Internally, the process has governance under the Director UK Electricity System Operator. National Grid ESO has also worked closely with LCP[25] 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 ESO, see the Annex A.9.

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

# 3. Scenarios & Sensitivities

## 3.1 Overview

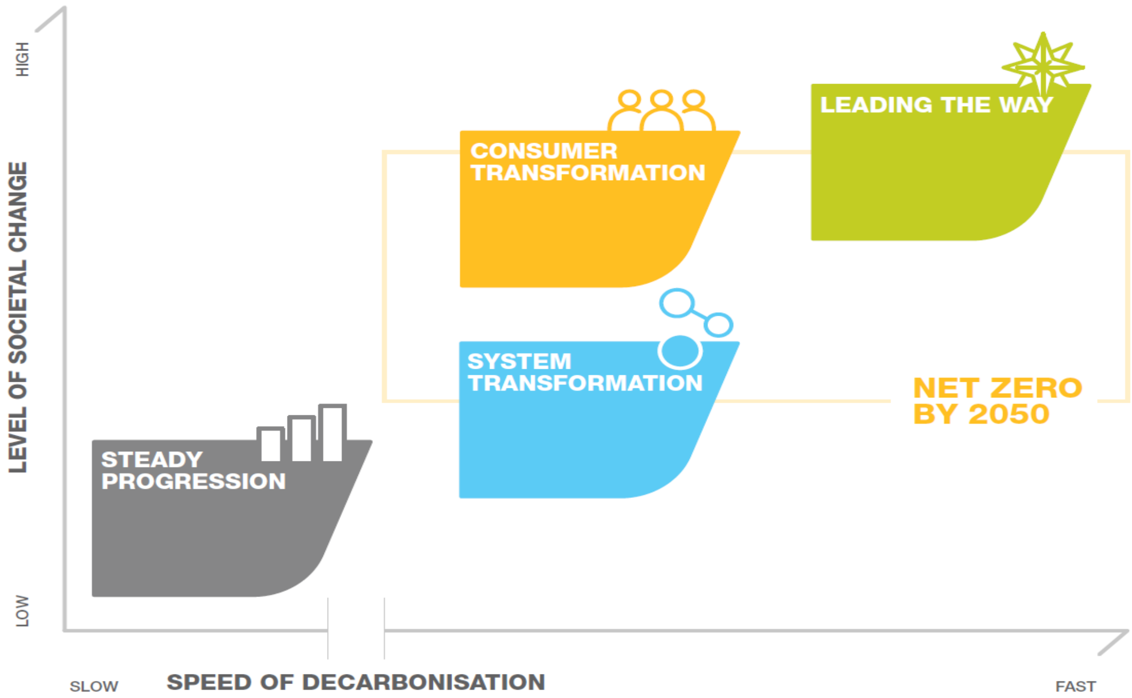
National Grid ESO have a well-established process to develop scenarios that reflect the uncertain supply and demand pathways on the future of energy in Great Britain. These scenarios are published annually in National Grid ESO's Future Energy Scenarios (FES) [26]. The scenarios consider the key challenges for the energy sector in meeting decarbonisation targets by 2050. The supply and demand assumptions developed in the FES are used for several ESO activities. These include network development (Electricity Ten Year Statement[27], Network Options Assessment[28]), operability (System Operability Framework[29]) and security of supply (ECR, Winter Outlook Report[30] and Summer Outlook Report[31]).

National Grid ESO has a well-established and extensive consultation process for the FES. This involves industry workshops, conferences, seminars, thought pieces and bilateral meetings. The engagement cycle culminates in the FES Stakeholder Feedback Document[32], which is submitted to Ofgem and published on our website. This includes details on how we have reflected stakeholder feedback in our scenario development and provides a look ahead to the upcoming FES.

In developing FES 2020, we engaged with over 200 different organisations. The 2020 Stakeholder Feedback Document describes the key changes to this year's scenarios which are expected to be published in the FES 2020 document in the week commencing 27th July 2020. The FES 2020 scenario framework has been designed to explore the most fundamental drivers of uncertainty in the future energy landscape and reflects extensive analysis and consultation with industry. The framework diagram is shown in Figure 6.

[26] http://fes.nationalgrid.com/
[27] https://www.nationalgrideso.com/research-publications/electricity-ten-year-statement-etys
[28] https://www.nationalgrideso.com/research-publications/network-options-assessment-noa
[29] https://www.nationalgrideso.com/research-publications/system-operability-framework-sof
[30] https://www.nationalgrideso.com/research-publications/winter-outlook
[31] https://www.nationalgrideso.com/research-publications/summer-outlook
[32] http://fes.nationalgrid.com/media/1457/stakeholder-feedback-document-2020.pdf

**Figure 6 : Scenarios Framework Diagram**




As compared to previous year, we have kept the *speed of decarbonisation* axis and introduced a new vertical axis: *level of societal change*[33]. In our engagement for FES 2020 stakeholders told us that while year-on-year consistency is valuable, the 2019 framework needed changing due to the increased ambition of the UK's decarbonisation target to meeting net zero[34] in 2050. Stakeholders also told us that *level of decentralisation* is no longer the most useful variable to flex to explore future uncertainty in energy, and *level of societal change* would allow us to explore different solutions for decarbonisation of heat (e.g. electrification vs low carbon gas) alongside changes in consumer engagement, levels of energy efficiency and a 'supply-led vs demand-led' approach. Our framework changes and the feedback we received are discussed in more detail in our Stakeholder Feedback Document.

We have modelled four scenarios; three which meet or exceed the new net zero target and one which does not. Two of our scenarios meet the target in 2050: System Transformation, which focuses on supply side decarbonisation, and Consumer Transformation, which relies on more significant changes in society and how consumers use energy. Steady Progression does not meet the target, while Leading the Way meets the target before 2050 and requires the highest levels of societal change.

The scenarios will continue to reflect a mix of technology options, taking account of the rapid changes in the energy industry, markets and consumer behaviour. Security of supply for both gas and electricity will be achieved across the scenarios for FES 2020, as in previous years.

[33] the new net zero target requires fundamental change across all elements of our energy system and society, but there is uncertainty around various paths to achieve net zero, with some paths requiring different levels of societal change than others. So, for FES 2020 we have continued to look at the speed of decarbonisation (how quickly the UK will decarbonise its economy) but added a new axis – level of societal change (how our economy will decarbonise).

[34] https://www.nationalgrideso.com/document/166306/download

For the purposes of modelling scenarios for the Capacity Market, BEIS's DDM model has been used, as described in both Chapter 2 and the Annex A.5. Thus, while the non-Capacity Market technologies are fixed to the levels assumed in each of the FES scenarios, the DDM calculates CM qualified capacity to ensure that the 3 hours LOLE Reliability Standard is met. Hence the capacities shown in this analysis may diverge from those in the original FES scenarios, which reflect what has actually happened in the market post auctions, incorporating any potential for over-delivery rather than the theoretical recommended target capacity.

### 3.1.1 Base Case

In addition to the four FES scenarios and to be compliant with our Demand Forecast Accuracy (DFA) Incentive, we have used a Base Case known as the 'five-year forecast' to 2024/25, against which all the sensitivities will be run. This case follows the same principles and modelling approach as the FES scenarios to give a five-year demand and generation background that is within the four FES scenarios range. Due to the inherent uncertainty across the market beyond 2024/25, we do not produce a forecast beyond the next five years. Instead, the Base Case follows the FES scenario that is closest in its peak demand to provide a 15-year view in the ECR. In FES 2020, the Base Case is closest to the System Transformation scenario and so we have aligned the Base Case to this scenario from 2025/26 onwards in our ECR analysis.

The Base Case takes account of Capacity Market units awarded agreements in the previous T-4 auctions that are now known not to be able to honour their contracts. It assumes that other capacity contracted in previous auctions is able to honour contracts over the next five years.

#### Energy demand

Demand reduction and decarbonisation continues at a steady pace due to economic, political and social focus elsewhere. In the Industrial & Commercial sectors, projections are based on the 'Oxford Economics' best view of economic growth with 1.3% average annual GDP growth fixed across all scenarios. Electricity demands reduce slightly. Demand in these sectors is heavily influenced by the size of the economy in the UK, which is assumed to have a fairly close trading relationship with the EU. The UK economy is forecast to expand slowly but demand is offset by policy, incentivising slow improvements in energy efficiency. Residential demands are based on the 'Oxford Economics' housing base view, central regression of 'Energy Consumption in the UK' data for appliances and energy efficiency, and inclusion of EU halogen lighting policy. Residential light demand falls rapidly with the policy driven phase-out of inefficient bulbs, and all other residential appliance demands fall at slow historic rates.

#### Transport

Electric cars increase in popularity for consumers as battery prices fall, range increases and more models become available on the market. We have seen significant acceleration in the growth of sales of battery electric cars and vans in 2019. As a result, the Base Case models a faster uptake than last year. For commercial road transport, electricity and natural gas increase in prevalence as emissions reduction and decarbonisation continues. In the transport sector projections are based upon a diffusion model to calculate the proportion of the potential market that adopts the technology at a given time based upon total cost of ownership in relation to the current dominant technology. This is done for motorbikes, cars, light goods vehicles (vans), heavy goods vehicles (HGVs) and buses & coaches; cars are further split down into compact, mid-sized and large segments.

### Heat

The next five years will see slow but steady progress towards decarbonisation of heat, through uptake of lower carbon technologies and thermal efficiency improvements, mainly via improved gas boiler standards (e.g. Boiler Plus in England) and better home insulation. Base Case numbers for fuel prices, technology costs, and available tariffs have been used to determine the marginal cost benefits of switching to low-carbon heating. Heat networks will continue their recent strong growth through continuing support from the Heat Networks Investment Project funding programme, although most schemes will continue to be powered by gas CHPs. Gas demand for heat will remain stable or decline slightly over this period whilst electricity demand for heating will see a small increase.

This year we have a lower thermal demand baseline than last year after adjustment to latest historical fuel consumption data. The baseline technology mix has also been recalibrated based on stakeholder feedback.

### Electricity supply

For electricity supply, the five-year forecast represents our best view of the generation that we expect to be operational. This includes generation connected to the transmission and distribution networks, as well as interconnectors and storage. This is based on a combination of market intelligence[35] and economic modelling. In most cases, we would expect generation to deliver in line with Capacity Market agreements and Contracts for Difference, although we make some allowance for non-delivery, dependent on market intelligence. The four scenarios then consider some of the uncertainties around this view. For example, this may include power stations closing early or staying open longer than expected; new projects being delivered ahead of schedule or delayed. These assumptions vary across the scenarios in line with the FES Scenario Framework.

### Gas supply

Global gas flows will remain subject to weather, market and political drivers over the next 5 years. UK gas production and development is expected to follow recent trends.

## 3.2 Scenario Descriptions

The four FES scenarios for 2020 are described below, including key assumptions in the areas of energy demand, transport, heat, electricity supply and gas supply.

### 3.2.1 Consumer Transformation

This scenario explores how the net zero target can be met in 2050 in a world with high levels of societal change.

[35] e.g. press releases / announcements, TEC register, embedded generation register, interconnector register, information from bilateral meetings with generators and/or project developers

## Energy demand

In Consumer Transformation, the 2050 net zero target is met with measures that have a greater impact on consumers and is driven by greater levels of consumer engagement in the energy transition. For example, a typical domestic consumer will use an electric heat pump with a low temperature heating system and an electric vehicle. They will have had extensive changes to their home to improve its energy efficiency and most of their energy demand is met by electricity with smart management and control. The system will have high peak electricity demands that will be managed with flexible technologies including energy storage, demand side response and smart energy management. Natural gas demand is lowest in this scenario.

## Transport

In Consumer Transformation, we see a high rate of uptake of battery electric vehicles, meeting a 2035 sales ban on ICE (internal combustion engine) cars, and 100% of car sales are battery electric vehicles in that year. This scenario sees the lowest demand for hydrogen of any of the net zero scenarios. This leads to slower decarbonisation of the last 10% of petrol/diesel demand in heavy goods vehicles due to the operational changes required to make some vehicles suitable for the technology. There is also greater growth in the number of public transport passenger miles in the high societal change scenarios.

## Heat

In Consumer Transformation, we assume high levels of improvement in thermal efficiency. Heat demand reductions are achieved by applying insulation measures in addition to consumers changing behaviours and higher compliance to standards to close performance gaps. In this scenario, we also assume no new home connections to the gas grid from 2025 to reflect the proposal in the government's Future Homes Standard, with new homes being heated by electric heat pumps and widespread conversion to heat pumps in existing properties, supplemented by hydrogen boilers and district heating, with some direct electric heating where heat pumps are less suitable. To meet the net zero target there is no unabated combustion of gas in dwellings.

## Electricity supply

Smaller, decentralised generation technologies that support decarbonisation such as onshore wind and solar are expected to be more prominent in this scenario. There is also still large growth in offshore wind generation in this scenario. This decarbonised world with high levels of renewable generation will also support the development of new sectors, such as hydrogen production by electrolysis. Battery storage is expected to play a key role in providing flexibility, with interconnectors and larger-scale storage also expected to be important. Biomass energy generation with carbon capture and storage (BECCS) will be important to achieve negative emissions in the power sector to meet net zero in the country as a whole.

## Gas supply

Hydrogen produced in this scenario is from electrolysis, and demand for natural gas falls sharply. We see the steepest decline in output from UK Continental Shelf (UKCS) and low levels of imported natural gas from Norway, continental Europe and liquefied natural gas (LNG).

### 3.2.2 System Transformation

This scenario explores how the net zero target can be met in 2050 in a world with lower levels of societal change.

#### Energy demand

In System Transformation, the typical domestic consumer will experience less disruption than in Consumer Transformation as more of the significant changes in the energy system happen on the supply side, away from the consumer. For example, a typical consumer will use a hydrogen boiler with a mostly unchanged heating system and an electric vehicle or a fuel cell vehicle, they will have had relatively fewer energy efficiency improvements to their home and will have lower engagement with opportunities to use their demand to provide flexibility to the system. Total hydrogen demand is high, and it is mostly produced from natural gas with carbon capture and storage.

#### Transport

In System Transformation, a 2035 sales ban on ICE cars will be met, and we see 100% battery electric car sales in that year. We see growing hydrogen demand for HGVs from the early 2030s due to the wide availability of hydrogen, and this grows to be larger than in any other scenario as a wider proportion of the total fleet adopts this zero-emission transport solution.

#### Heat

In System Transformation, we assume medium levels of improvement in thermal efficiency. Heat demand reductions are achieved by applying insulation measures and higher compliance to standards to close performance gaps, with some contribution from consumer behaviour change. In this scenario, we assume policy prioritises repurposing of existing infrastructure to decarbonise heating, so new home connections to the gas grid continue post-2025. Homes are primarily heated by hydrogen boilers as the gas network is converted to deliver hydrogen. This is supplemented by some take-up of electric heat pumps, hybrid heat pump/hydrogen boilers and district heating, with some direct electric heating. To meet the net zero target there is no unabated combustion of gas in dwellings.

#### Electricity supply

Larger, centralised generation technologies that support decarbonisation such as offshore wind, nuclear and carbon capture utilisation and storage (CCUS) are expected to be more prominent in this scenario. Interconnectors and storage (both larger-scale and smaller batteries) are expected to play a key role in providing flexibility. BECCS will be important to achieve negative emissions in the power sector to meet net zero in the country as a whole.

#### Gas supply

High levels of hydrogen produced from steam methane reformation of natural gas requires high volumes of this to decarbonise heat and I&C. This scenario sees relatively high output from UKCS production and natural gas import from Norway, Continental Europe and LNG. Investment is reduced in UK shale solutions, as focus moves more to green technologies.

### 3.2.3 Leading the Way

This scenario explores how the net zero target can be met before 2050 in a world with the highest levels of societal change.

#### Energy demand

In Leading the Way, we assume that GB decarbonises rapidly with high levels of investment in world-leading decarbonisation technologies. In this scenario, our assumptions in different areas of decarbonisation are pushed to the earliest credible dates. Consumers are highly engaged in acting to reduce and manage their own energy consumption. This scenario includes the highest and fastest improvements in energy efficiency to drive down energy demand, with homes retrofitted with insulation such as triple glazing and external wall insulation, and a steep increase in consumer participation in smart energy services. Hydrogen is used to decarbonise some of the most challenging areas of society such as some industrial processes; with this hydrogen produced primarily from electrolysis, powered by renewable electricity. The highest levels of energy efficiency lead to the lowest overall energy demands in this scenario.

#### Transport

In Leading the Way, we see 100% battery electric vehicle sales in 2032, exceeding the current government ambition of 2035. We see increasing hydrogen demand for transport, particularly in heavy goods vehicles. We also start to see a reduction in the number of cars on the roads after 2040 due to autonomous vehicles changing car ownership patterns and taking cars off the road. There is also greater growth in the number of public transport passenger miles in the high societal change scenarios.

#### Heat

In Leading the Way, we assume the highest levels of improvement in thermal efficiency. Heat demand reductions are achieved by applying insulation measures in addition to consumers changing behaviours and higher compliance to standards to close performance gaps. In this scenario, we also assume no new home connections to the gas grid from 2025 to reflect the proposal in the government's Future Homes Standard. New homes are heated by electric heat pumps, while existing homes are converted to heat pumps or hydrogen boilers, supplemented by district heating, with some direct electric heating. To meet the net zero target there is no unabated combustion of gas in dwellings.

#### Electricity supply

This scenario sees the fastest growth in renewable generation until the 2030s, with high levels of offshore wind, onshore wind and solar. BECCS will be important to achieve negative emissions in the power sector to meet net zero in the country as a whole. This scenario sees the highest level of interconnection capacity and high levels of energy storage to provide flexibility.

#### Gas supply

There is further reduction in shale investment due to reduction in unabated gas demand, medium levels of electrification, combined with some gas demand for hydrogen production. Residual gas demands are met through a combination of UKCS production, and imports of gas such as from Norway, Continental Europe and LNG.

Import of green hydrogen offers a lower carbon option than steam methane reformation with CCUS and so would help GB achieve its net zero ambition early.

### 3.2.4 Steady Progression

This scenario explores the minimum credible level of decarbonisation between now and 2050 and the lowest likely levels of societal change we could see.

#### Energy demand

In Steady Progression, there is still progress made on decarbonisation compared to the present day, however it is slower than in the other scenarios. This scenario is expected to have the lowest level of consumer engagement and slower improvements in appliance efficiency compared to the net zero compliant scenarios. However, growth of electric vehicles will mean that smart technology is still important in managing peak electricity demand. Gas demand is likely to remain high as gas continues to be used in both heating and electricity generation. In 2050 this scenario still has significant annual carbon emissions, which is short of the 2050 net zero target in UK legislation.

#### Transport

Electric vehicle take-up grows more slowly than in other scenarios, displacing petrol / diesel vehicles for domestic use. Decarbonisation of other vehicles is slower still, with continued reliance on diesel for heavy goods vehicles. Steady Progression this year shows a faster uptake of EVs than in the equivalent scenario from 2019 as we have seen significant acceleration in the growth of battery electric vehicles in 2019. We also see some increased demand for natural gas vehicles in the HGV sector.

#### Heat

Homes are likely to gradually become more thermally efficient in this scenario, but slower than in the net zero compliant scenarios. In this scenario, we assume more lax enforcement of standards as policy prioritises affordable housing, and new home connections to the gas grid continue post-2025. The predominant home heating technology in 2050 continues to be gas boilers, but with low levels of hydrogen blend in the fuel mix and increased use of biogas. This is supplemented by some take-up of electric heat pumps, particularly in new builds and off-gas grid dwellings.

#### Electricity supply

Larger, centralised generation technologies are expected to be more prominent in this scenario. However, the deployment of technologies that support decarbonisation such as offshore wind and nuclear is expected to be slower than in the net zero compliant scenarios. This may place greater reliance on gas, particularly larger combined cycle gas turbines (CCGTs), for both generation and flexibility. Interconnectors and storage are also expected to provide flexibility.

### Gas supply

We see continued demand for natural gas for heat and industry. GB focusing on indigenous production from UKCS reduces the flows from continental Europe and LNG. Some investment in shale gas is prioritised due to the importance of gas in the energy mix.

## 3.3 Demand Forecast until 2024/25

This 'Five Year Forecast' covers the period 2020/21 to 2024/25. It supports the Demand Forecast Accuracy (DFA) incentive, which along with EMR sensitivity analysis and the four scenarios is a key driver of the capacity to secure. Industrial and commercial demand comprises one component of the peak forecast and is based on current views of energy policy and the latest 'Oxford Economics' baseline economic and price forecasts at the time of scenario creation in Q4 2019. Residential demand comprises the other component of peak and takes into account energy policy, consumer behaviour and uptake of new technologies such as electric vehicles and heat pumps.

The Base Case peak underlying demand forecast is lower this year than the forecast in 2019. This year's forecast for 2024/25 (57.5 GW) is 1.4 GW lower than the 2019 forecast for 2023/24 (58.9 GW) and 1.6 GW lower than the 2019 forecast for 2024/25 (59.1 GW).

There are four elements driving the 1.6 GW change in underlying demand by 2024/25:

- The 0.2 GW difference in 2018/19 outturn from provisional (59.6 GW) to confirmed (59.4 GW)
    - This was a difference in weather-corrected metered demand
- Residential demand is 0.9 GW lower by 2024/25 largely due to lighting demand
    - Latest data shows a greater reduction than expected – most likely the impact of the EU halogen ban
- Industrial demand is 0.8 GW lower by 2024/25
    - Reduction is mainly due to higher energy efficiency with a small element due to the lower economic output forecasts used in our analysis compared to last year's central forecast. The lower economic output forecasts used in our analysis, in part reflect the potential for a harder Brexit than assumed in our 2019 modelling.
- The decreases are partly offset by increases (0.3 GW) in electrification of transport and heat
    - Evidence of greater Electric Vehicle sales
    - Greater Heat Pump demand

Figure 7 and Table 6 show the peak demands for the Base Case and the FES scenarios over the five-year period. The chart also shows historic peak demands since 2015/16.

**Figure 7: Peak Demand - FES Scenarios and Base Case to 2024/25**

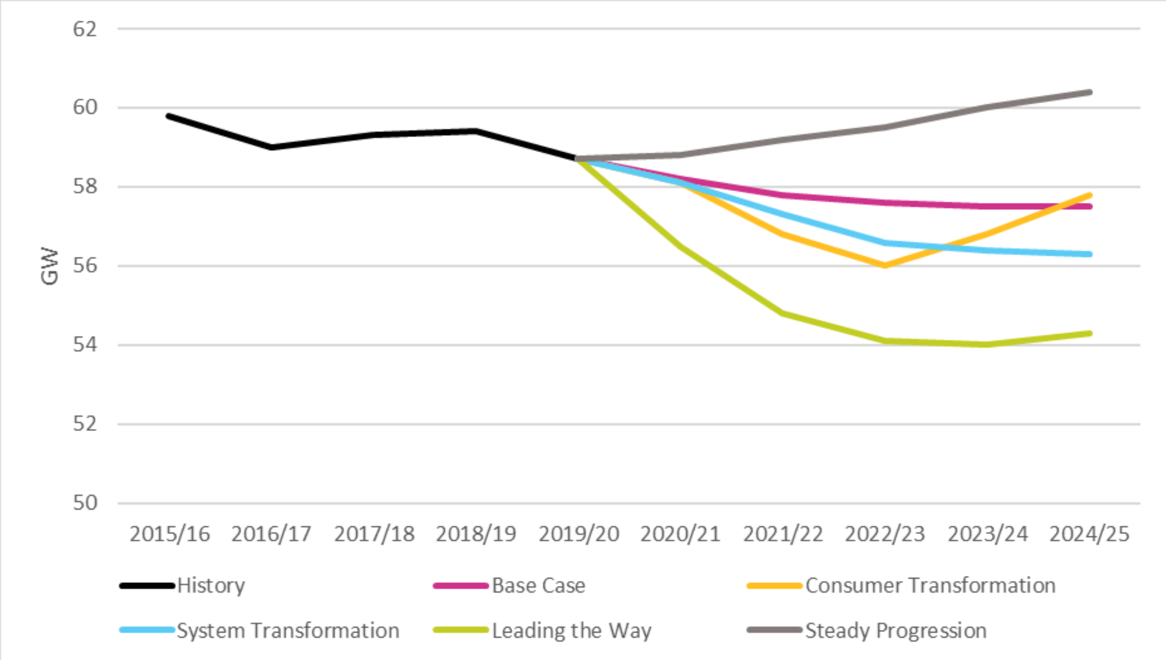



**Table 6: Peak Demand to 2024/25**

| Peak Demand GW | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
|---|---|---|---|---|---|---|
| **Base Case** | 58.7 | 58.2 | 57.8 | 57.6 | 57.5 | 57.5 |
| **Consumer Transformation** | 58.7 | 58.1 | 56.8 | 56.0 | 56.8 | 57.8 |
| **System Transformation** | 58.7 | 58.1 | 57.3 | 56.6 | 56.4 | 56.3 |
| **Leading the Way** | 58.7 | 56.5 | 54.8 | 54.1 | 54.0 | 54.3 |
| **Steady Progression** | 58.7 | 58.8 | 59.2 | 59.5 | 60.0 | 60.4 |

In May 2019, the UK Government amended the 2008 Climate Change Act, changing the 80% greenhouse gas reduction target to 'net zero emissions'. We consulted with the energy industry and stakeholders on draft scenarios and used feedback to finalise and refine the 2020 projections. Three of the four scenarios achieve net zero emissions by 2050. In these scenarios, all sectors of UK society are decarbonised as much as possible by 2050. Electrification of heat and transport, the requirement to substitute almost all fossil fuels, along with population growth result in increased demands. This is offset by energy efficiency, fuel prices or fuel substitution for hydrogen in System Transformation. Biomass utilisation is similar across all scenarios as this area is highly uncertain, and availability or scarcity has a significant impact on energy mixes.

Compared to the FES 2019 scenarios, the FES 2020 scenarios have a weaker economic outlook, which affects all scenarios up to 2024/25. The following narrative compares the 2020 scenarios against those used last year.

Steady Progression in FES 2019 and FES 2020 share a similar trajectory as the demand assumptions are very similar.

System Transformation 2020 has less fuel substitution to electricity than Two Degrees 2019, reflecting the possibility of large-scale hydrogen by 2030 which discourages electrification of heat, industrial demand and commercial demand.

Up to 2022, the decentralised and highly electrified 'Consumer Transformation 2020' tracks Community Renewables 2019 due to similar energy efficiency assumptions. Consumer Transformation then rapidly grows due to the adoption of electricity to power road transport and earlier heat decarbonisation than assumed in 2019.

'Leading the Way' is new for FES 2020 and achieves the net zero targets early. Up to 2026, demands are lower than all other scenarios. This is due to higher energy efficiency assumptions that were proposed by the EU for 2030 but not adopted, in order to illustrate a potential low carbon, high efficiency, pathway.

## 3.4 Demand Forecast 2025/26 onwards

The scenarios have evolved every year in order to better reflect a range of credible demand scenarios. As well as a wider range of fuel prices and general energy efficiencies, we have reviewed all the FES components including adoption of electrified road transport, low carbon heat and residential thermal insulation. Demand is expected to increase from the mid-2020s due to adoption of electrified road transport and electrified, low carbon heat. Key uncertainties are the levels of 'smart' energy use to reduce system peak (particularly from electric vehicle charging and heat storage) and the speed of adoption.

Post 2025, Steady Progression in FES 2019 and FES 2020 share a similar trajectory as the demand assumptions are very similar.

System Transformation 2020 has more hydrogen than Two Degrees 2019 in order to illustrate a society more based on hydrogen than in 2019. Industry and Commercial demand, heat and heavy transport move to hydrogen where possible, reducing potential growth of the electricity system. Peak electricity demands are therefore lower in System Transformation than Two Degrees.

Consumer Transformation demands are significantly higher than Community Renewables in FES 2019 as there is less hydrogen and natural gas in the energy mix, despite high levels of energy efficiency and time of use tariffs. Like 2019, new cars are mostly electric by 2035, but commercial vehicles go heavily electric in the period to 2050, whereas in 2019 there were more gas, hydrogen and biofuel vehicles. More heat pumps are assumed this year, to reflect a more electrified world. As a result, demands are significantly higher than Community Renewables due to more overall electrification and less hydrogen, natural gas and biofuels in the energy mix.

In 'Leading the Way', demands increase after 2025 due to decarbonisation of transport and heat using a mix of hydrogen and electricity – electricity demand in this world is between Consumer Transformation and System Transformation.

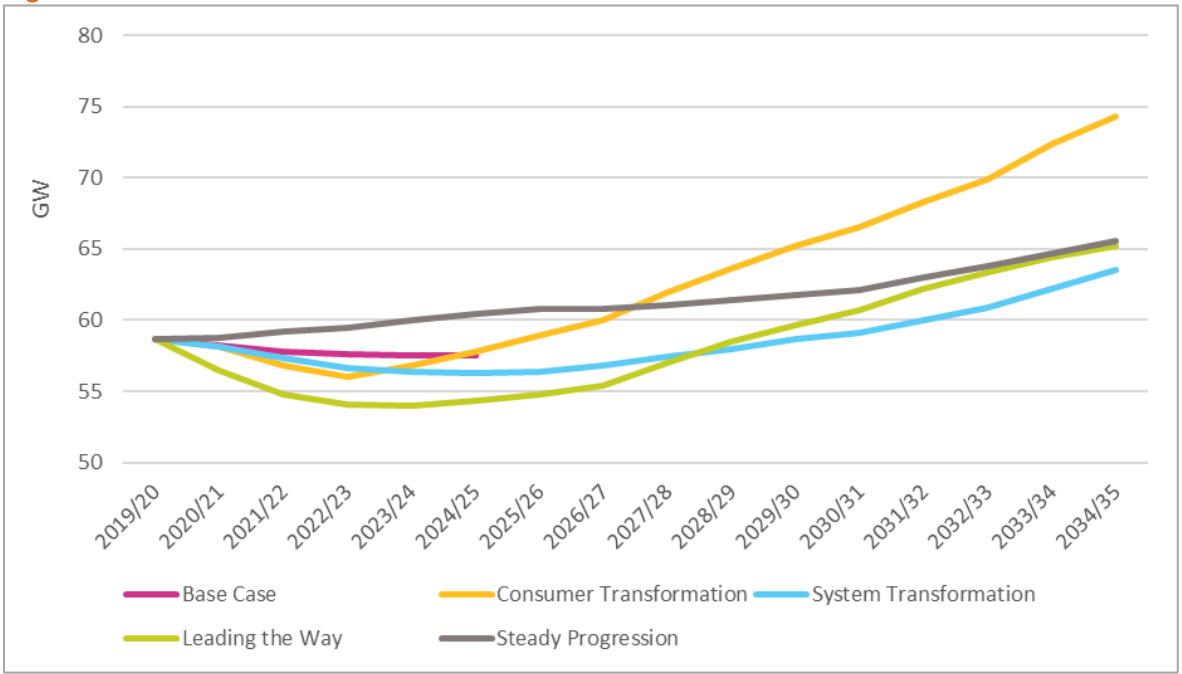
The definition of peak demand used in the modelling is Unrestricted GB National Demand[36], plus demand supplied by distributed generation. Reserve required to cover for the single largest infeed loss is not included in the demand definition but is included in the modelling.

Demand is based on the Average Cold Spell[37] (ACS) peak demand and is consistently applied within the sensitivities applied to the Base Case. The only adjustments to ACS peak demand are for the high and low demand sensitivities. All forms of DSR greater than 1 MW are eligible for the Capacity Market under proposed changes. This can include DSR through the use of an aggregation service (including DSR <1 MW). Note that this includes DSR at times of Triad charging periods. Therefore, unrestricted peak demand is modelled, i.e. no DSR or Triad avoidance has been subtracted.

Please refer to Annex A.1 for details on the demand assumptions used in the FES scenarios and Section 3.8 for more details on DSR.

Figure 8 shows the peak demands used in the DDM modelling to 2034/35.

**Figure 8: Peak Demand - FES Scenarios and Base Case to 2034/35**




## 3.5 Generation Capacity until 2024/25

Our generation capacity assumptions from 2019/20 to 2024/25 are based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years.

[36] National demand is defined in the Grid Code 'Glossary and Definitions' https://www.nationalgrideso.com/codes/grid-code?code-documents=

[37] 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.

The Base Case sits within the uncertainty envelope provided by the 2020 Future Energy Scenarios as shown in Figure 9. Transmission nameplate capacities (including interconnection) are shown in Table 7.[38]

**Figure 9: FES 2020 Transmission connected nameplate capacity to 2024/25**

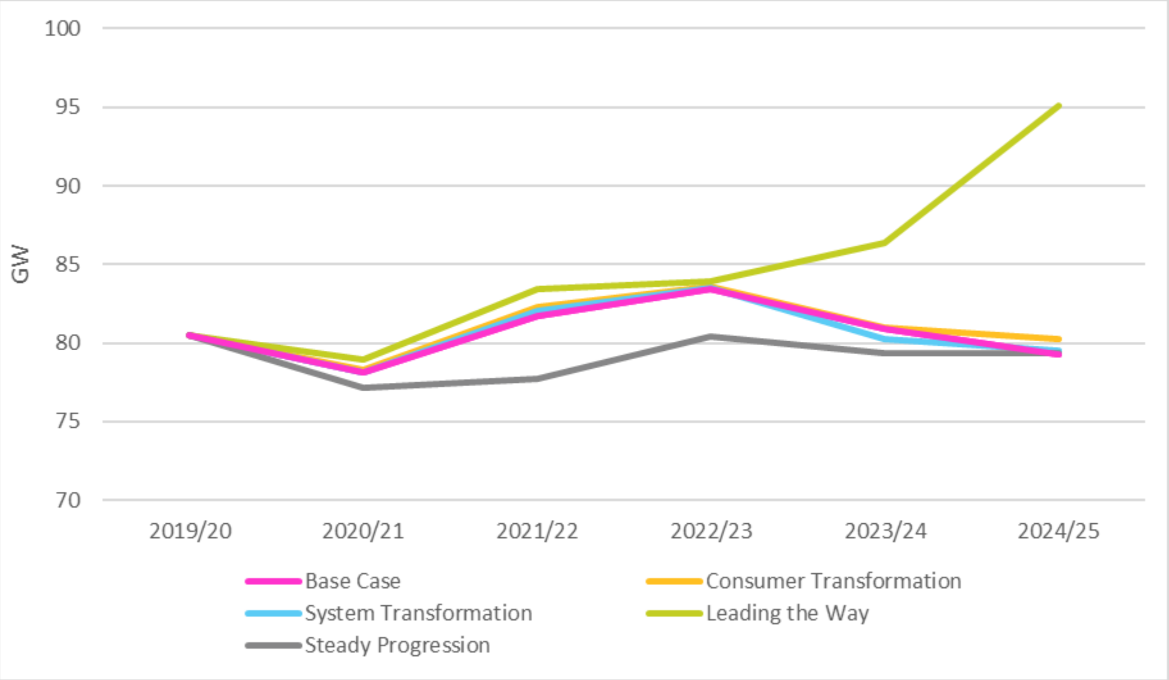



**Table 7: Transmission connected nameplate capacity (GW) to 2024/25**

| Capacity GW | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
|---|---|---|---|---|---|---|
| **Base Case** | 80.5 | 78.1 | 81.7 | 83.5 | 80.9 | 79.3 |
| **Consumer Transformation** | 80.5 | 78.3 | 82.3 | 83.6 | 81.0 | 80.2 |
| **System Transformation** | 80.5 | 78.1 | 82.0 | 83.5 | 80.3 | 79.5 |
| **Leading the Way** | 80.5 | 79.0 | 83.5 | 83.9 | 86.3 | 95.1 |
| **Steady Progression** | 80.5 | 77.1 | 77.7 | 80.4 | 79.4 | 79.4 |

We consider the impact of the Industrial Emissions Directive (IED) on both large plant (via the EU's Large Combustion Plant Directive) and medium plant (via the Medium Combustion Plant Directive (MCPD) and the more onerous rules applied by DEFRA). For large plant, we consider the impact on a case by case basis as the option that each generator took has an impact on the expected running hours and closure date. For example, those plant that entered into the Limited Life Derogation (LLD) can run for no more than 17,500 hours starting on 1 January 2016 and ending no later than 31 December 2023.

Like with large plant, the emission limits for medium plant depend on numerous factors including the build date and whether the plant was awarded contracts in the 2014 or 2015 capacity auctions. The greatest impact is on the diesel reciprocating engines. Following stakeholder engagement we assume there will be a transition away from diesel reciprocating engines as a result of the emissions directive and the general market

[38] Note that this includes all transmission-connected capacity including interconnectors

conditions.

In addition to the IED and MCPD, there is a proposal to introduce carbon emissions limits in future Capacity Market auctions.[39] While this does not directly impact our modelling for the ECR, we note that there may be impacts on capacity market participants from this.

## 3.6 Generation Capacity 2025/26 onwards

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

### Capacity Market eligibility

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

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

However, once a plant stops receiving support under these schemes, it will become eligible for the Capacity Market (assuming the CM rules allow it to participate).

In addition, to be consistent with proposed changes[40], any generation capacity that is under a total capacity of 1 MW is assumed not to be eligible for the Capacity Market in this modelling – although any plant under 1 MW not receiving support from the above schemes can enter the auction if combined with other capacity by an aggregator. This latter group is estimated to range from 0.6 to 0.8 GW over the period to 2024/25 depending on the FES scenario and year and includes some onsite autogeneration above 1 MW assumed to opt out of the Capacity Market. Note that small scale renewable technologies are assumed to receive FiT support and therefore are excluded from this range.

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

### Assumptions

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

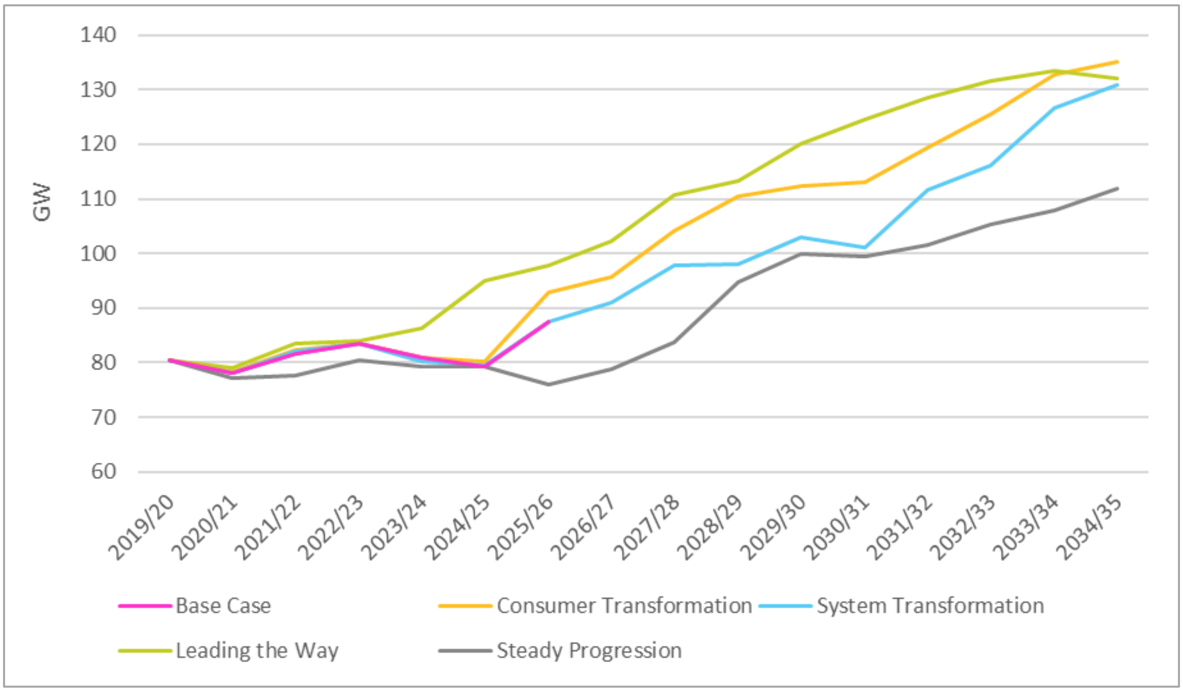
- All eligible capacity will enter the Capacity Market and
- No capacity will opt-out and remain operational.

[39] https://www.gov.uk/government/consultations/capacity-market-carbon-dioxide-emissions-limits
[40] https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

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

The focus of the modelling is to estimate the total eligible de-rated capacity that needs to be secured in order to achieve a reliability standard of 3 hours LOLE or lower. The final mix of generation technologies that make up this total capacity will be decided by the capacity auction and is not predetermined as a result of the modelling. A breakdown of installed capacity for each FES scenario is shown in Figure 10.

**Figure 10: FES 2020 transmission connected nameplate capacity to 2034/35**




Annex A.4 contains a breakdown of generation that is eligible and not eligible for the CM. Further details of the underlying generation assumptions, including the technology mix, will be available when the FES 2020 document is published week commencing 27th July 2020.[41]

## 3.7 Distributed Generation

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

The scenarios consider around 30 different existing technologies, as well as considering new types of generation that may connect in the future. The contribution of each of these technologies to peak demand is also taken into account – so for example, solar is excluded

[41] The ECR 2020 modelling was carried out using the FES assumptions that were provided on 15th April 2020. Since then some small changes have been made, particularly to assumptions in later years, which do not impact our recommendation. However, this may result in an apparent discrepancy between the FES data included in the 2020 ECR and that published in FES 2020 (expected to be week commencing 27th July 2020)

from these projections, due to the assumption that it is unable to contribute to peak demand which currently takes place in the hours of darkness[42].

A variety of data sources[43] are used to develop a list of projects for existing generation above 1 MW in size. We are continually seeking to improve the data available, as well as our analysis, in order to have an improved picture of how distributed generation operates over the year. This will help us to improve our understanding of how small-scale plant contributes to demand across the seasons.

The ECR uses overall underlying demand (See Section 3.4). For other purposes, demand on the transmission network can be calculated using the output from distributed resources netted off overall demand. Figure 11 and Table 8 show nameplate capacities (excluding solar) for distributed generation out to 2024/25. Figure 12 extends the capacities out to 2034/35.

**Figure 11: Distributed generation nameplate capacity (excl. solar) to 2024/25**

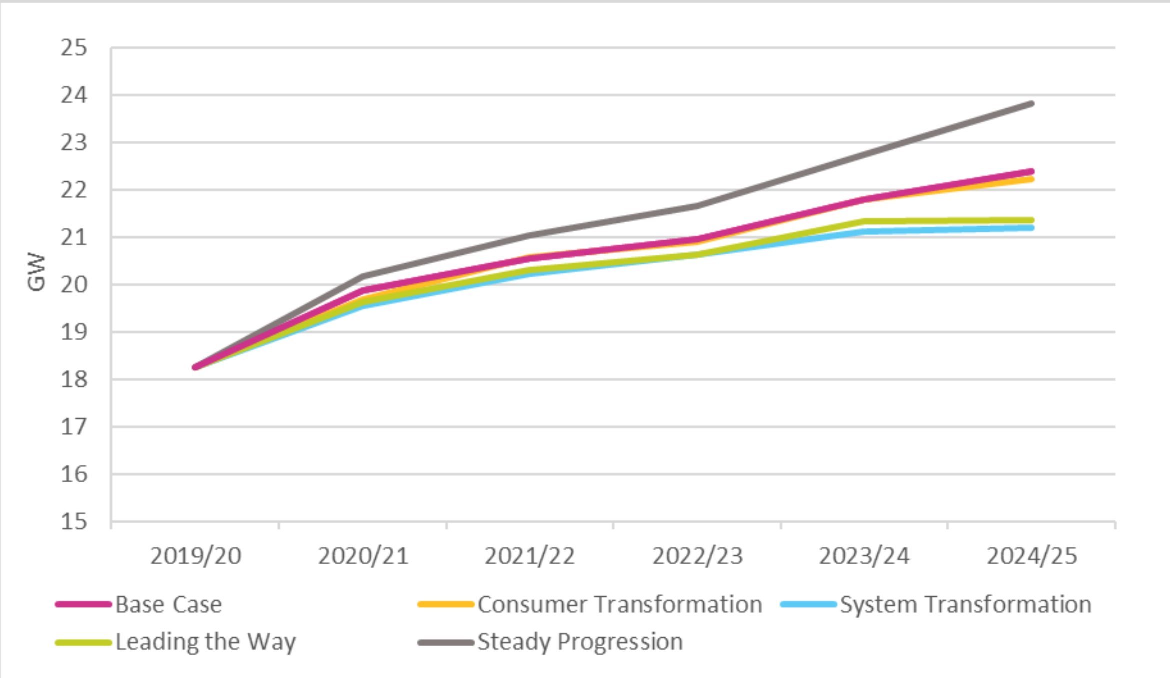
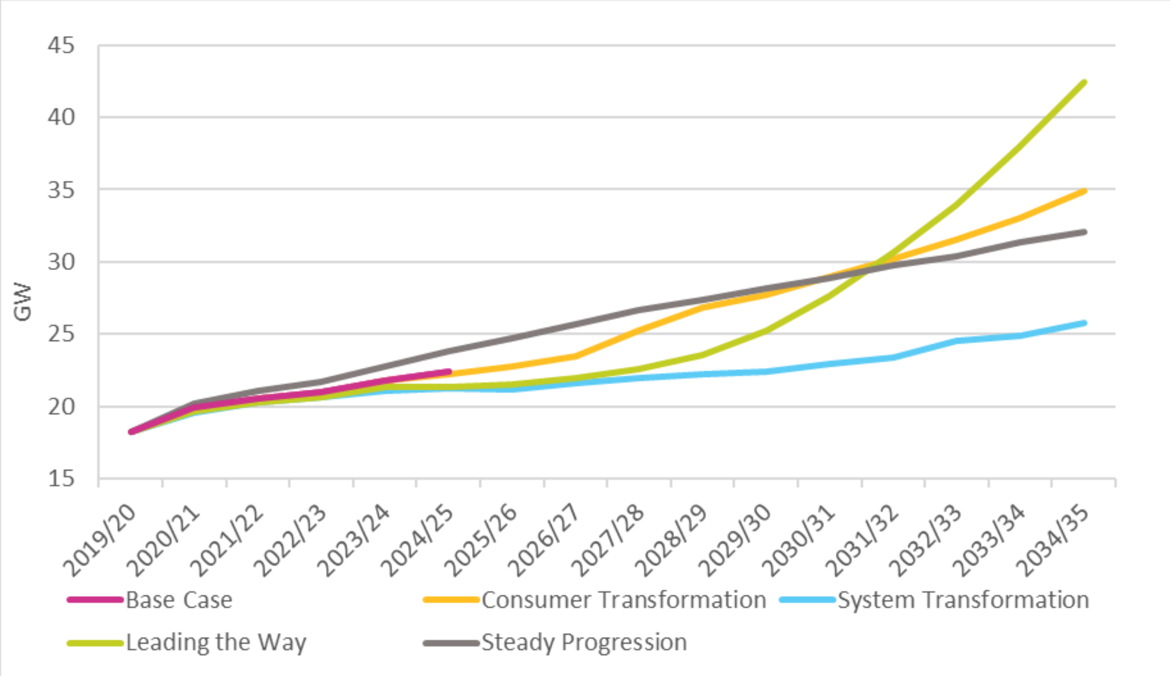



**Table 8: Distributed generation nameplate capacity (excluding solar) (GW)[44]**

| Capacity (GW) | 2019/20 | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 |
|---|---|---|---|---|---|---|
| **Base Case** | 18.3 | 19.9 | 20.6 | 21.0 | 21.8 | 22.4 |
| **Consumer Transformation** | 18.3 | 19.7 | 20.6 | 20.9 | 21.8 | 22.2 |
| **System Transformation** | 18.3 | 19.6 | 20.2 | 20.6 | 21.1 | 21.2 |
| **Leading the Way** | 18.3 | 19.6 | 20.3 | 20.6 | 21.3 | 21.4 |
| **Steady Progression** | 18.3 | 20.2 | 21.0 | 21.7 | 22.8 | 23.8 |

[42] The de-rating factor for solar is less than 4% for CM auctions
[43] For example, Renewable Energy Planning Database, CM register, DNO long term development statement and others
[44] Includes capacity <1 MW

**Figure 12: Distributed Generation (excluding Solar) to 2034/35 (GW)**




## 3.8 Demand Side Response

In the FES, demand side response (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 and switching to an alternative supply source (which is included in the distribution connected generation technologies). Within our definition of DSR, we consider only the demand reduction element.

Historically, information available to us indicated around 50% of Triad avoidance is due to alternative supply sources. Observed Triad avoidance in Winter 2018/19 increased by 0.4 GW to 2.4 GW compared to Winter 2017/18. Discussions with customers indicate that this was largely due to new generation capacity and storage. Observed Triad avoidance in Winter 2019/20 remained at 2.4 GW.

### Domestic Peak Response

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

**Smart Meters:** These only have a short-lived behavioural impact by themselves. Crucially they enable robust adoption of time of use tariffs which potentially have wider benefits across the energy system. Their impact is enhanced where they are supported by appropriate marketing and education around energy use.

**Smart Technology:** These are appliances that have two-way communication capability and interact with the consumer and other parties; for instance, Hive or Nest. As the technology improves, service providers such as aggregators have a greater role to play.

**Smart Pricing:** The appropriate use of time of use tariffs (TOUTs). TOUTs incentivise consumers to move those energy demanding activities, which can be moved, to off peak times. The more engaged consumers, energy suppliers and government are, the greater the effects of TOUTs.

### Industrial and Commercial DSR

In FES, we define DSR as the turning up / down or turning off / on of electricity consumption in response to external signals. In our scenarios, we are modelling end use demand. Therefore, if a consumer chooses not to reduce their demand but instead switches to an alternative energy source, such as an onsite diesel generator or batteries, then we do not regard this as DSR.

Although there is uncertainty over the projected levels of industrial and commercial DSR, it should be noted that the DSR assumptions do not directly impact the recommended capacity to secure since we use unrestricted peak demand in our modelling (see Section 2.1). Furthermore, in the capacity auctions, DSR competes with other types of new / existing eligible capacity to meet the capacity requirement.

Figure 13 shows the industrial and commercial DSR for the scenarios to 2034/35, with Table 9 showing projections to 2024/25 and spot years for 2029/30 and 2034/35. There is uncertainty in the range of projections in the next 5 years. On the upside, for the next ten to fifteen years, in all the scenarios, there is a growth and development in the enabling systems, such as information communications technology, which permit DSR to evolve. Uncertainty is expected to result from the 2019 Targeted Charging Review[45] demand residual reforms which are due to be implemented in April 2022, and will change charging arrangements for use and access to the GB transmission system. Historically, Triad avoidance provided most of the commercial incentive for DSR and behind meter storage or generation. From April 2022, peak demand avoidance actions will no longer reduce system charges to the extent they did previously. The commercial driver for DSR will pivot away from system charges, and move mostly onto wholesale market price exposure. Changes to market behaviour and DSR are therefore difficult to anticipate as the duration of wholesale market prices may or may not be sufficient to justify DSR actions or investment in DSR enabling technologies (such as storage / generation or control systems).

In Steady Progression, the DSR market develops slowly over time. In System Transformation, a significant proportion of industrial and commercial demand moves away from electricity and onto hydrogen. As demands are lower there is less industrial and commercial demand, and less DSR potential. Of the net zero scenarios, System Transformation has the lowest DSR levels and the results are similar to those in the 2019 Two Degrees scenario. In Consumer Transformation, as hydrogen is a premium fuel, industrial and commercial demand electrifies as much as possible, particularly in the areas of space heat, commercial heat pumps and other secondary systems which are potentially available for DSR. Consumer Transformation has the highest customer electricity demand of the 2020 scenarios and therefore the highest levels of DSR, 1.5 GW above the levels seen in FES 2019 by the mid-2030s (reflecting higher demands and higher levels of electrification). Leading the Way is 1 GW higher than FES 2019 levels, only 0.5 GW below Consumer Transformation despite lower electricity demands (this is a mixed scenario with both hydrogen and electricity fuelling the GB economy). Leading the Way has relatively

[45] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

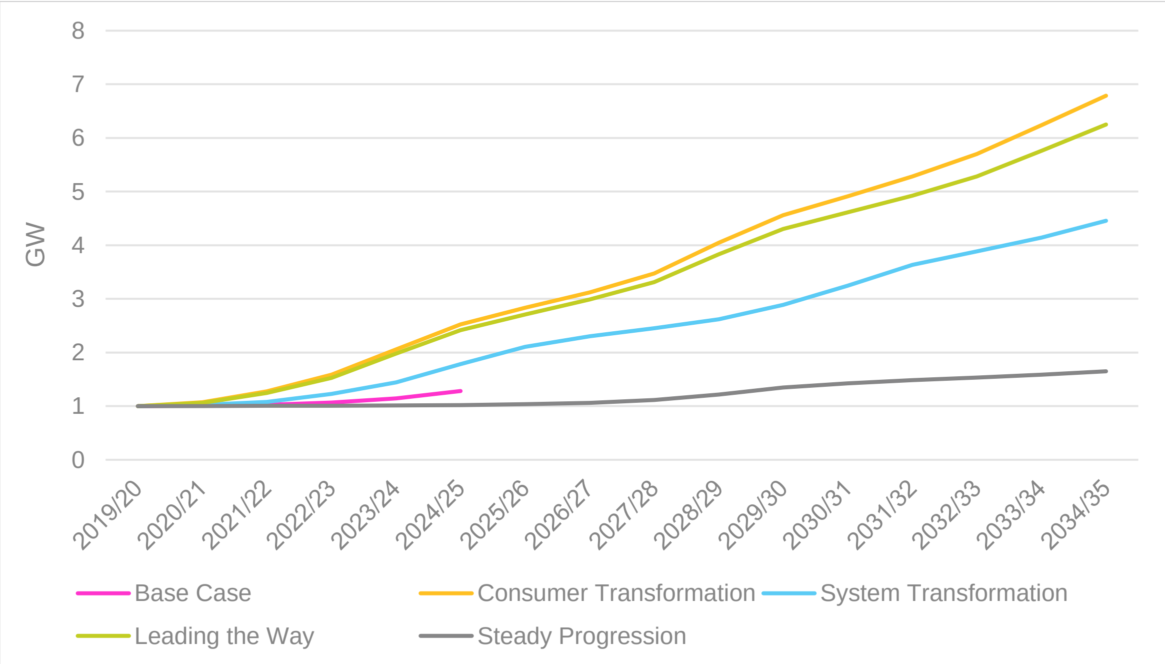
high levels of DSR as this scenario reflects a rapid drive to as efficient and smart system as possible.

The range of DSR by 2034/35 is 1.6 GW - 6.8 GW, which overlaps and exceeds the FES 2019 range of 1.6-5.3 GW by 2033/34 modelled in 2019. This reflects the greater DSR potential that results from higher demands in net zero, more heavily electrified scenarios than modelled in 2019.

**Table 9: Industrial and Commercial DSR (GW)**

| I&C DSR (GW) | 2020/21 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2029/30 | 2034/35 |
|---|---|---|---|---|---|---|---|
| **Base Case** | 1.0 | 1.0 | 1.1 | 1.1 | 1.3 | 2.9 | 4.5 |
| **Consumer Transformation** | 1.1 | 1.3 | 1.6 | 2.1 | 2.5 | 4.6 | 6.8 |
| **System Transformation** | 1.0 | 1.1 | 1.2 | 1.4 | 1.8 | 2.9 | 4.5 |
| **Leading the Way** | 1.1 | 1.2 | 1.5 | 2.0 | 2.4 | 4.3 | 6.3 |
| **Steady Progression** | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.3 | 1.6 |

**Figure 13: Industrial and Commercial DSR to 2034/35**




## Power Responsive

Power Responsive[46] is a stakeholder-led programme facilitated by National Grid ESO in order to grow participation of flexible technologies (including demand side response and storage) in demand side markets, build confidence in the demand side proposition, and support the evolution of demand side markets in GB. The programme involves all stakeholders in the value chain, including the demand side providers and energy consumers.

[46] http://powerresponsive.com/

Since the programme launched in summer 2015, there has been a substantial increase in momentum across the industry in the desire to facilitate the growth of participation of flexible technologies in energy markets. Around 2500 individuals have signed up to be informed on the programme so far and informative materials on opportunities to participate have been published, including a 'comprehensive guide to DSR' for energy managers in collaboration with the Major Energy Users Council. There are also regular open forum working groups for both DSR and storage sectors, and industry specific workshops to engage with I&C customers.

## 3.9 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects. We have anonymised the data by showing only the total capacity per year, due to commercial sensitivities. Our assumptions in the Base Case and Future Energy Scenarios broadly assume a system is put in place that closely resembles the arrangements under the IEM. This, for example, means that we assume there are no additional barriers to interconnector flows. We also assume that the total GB carbon price includes a component that continues on a similar trajectory to the EU Emissions Trading Scheme. However, we have assumed that the current political uncertainty means that there are no new interconnectors in our Base Case by 2024/25 apart from those that have either already started construction or taken a final investment decision.

We identified potential projects and their expected commissioning dates to connect to GB. This information was derived from a range of sources including National Grid ESO's interconnector register, the electricity European Network of Transmission System Operators (ENTSO-E) Ten-Year Network Development Plan, 4C Offshore and the European Commission. Where only a commissioning year was given, we assumed the date to be 1 October of that year. We assessed each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it did not meet the minimum criteria, we assumed it will not be delivered in the given scenario, or that it will be subject to a commissioning delay. We calculated this delay using a generic accelerated high-voltage direct current (HVDC) project timeline. All projects which have reached final investment decisions are delivered, though they may be subject to delays in some scenarios. In addition, all projects are assumed to be available in any year that they have already secured a capacity market agreement in all scenarios.

In all scenarios, we assumed that the supply chain has enough capacity to deliver all interconnector projects.  Although the Base Case is developed separately for the first five years, it aligns to the System Transformation scenario thereafter.

Table 10 depicts the import capacity levels of interconnection for each scenario. Interconnector capacity is assumed to be higher in scenarios that meet decarbonisation targets. Furthermore, interconnector capacity is generally also higher in scenarios with higher levels of societal change. As such, the highest electricity interconnector capacity is in Leading the Way and the lowest is in Steady progression. Interconnector capacities in both Consumer Transformation and System Transformation fall in between these limits.

**Table 10: Import Capacity Levels for Interconnection (GW)**

| Capacity (GW) | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2030/31 |
|---|---|---|---|---|---|---|
| **Base Case** | 7.0 | 8.4 | 8.4 | 8.4 | 9.8 | 17.9 |
| **Consumer Transformation** | 7.0 | 8.4 | 8.4 | 9.8 | 14.5 | 18.7 |
| **System Transformation** | 7.0 | 8.4 | 8.4 | 8.4 | 9.8 | 17.9 |
| **Leading the Way** | 7.0 | 8.4 | 9.8 | 15.1 | 17.9 | 21.5 |
| **Steady Progression** | 4.8 | 7.0 | 8.4 | 8.4 | 8.4 | 15.9 |

Building on from the work in the previous years, the analysis to assess interconnector flows has been conducted using a pan-European model called BID3 that we have procured from Afry[47]. Flows were modelled for each scenario based on the latest available FES 2020 data for Great Britain. The assumptions for other European countries were informed by our European scenarios as described in Section 4.2. These assumptions were based on reports published by other European Transmission System Operators and ENTSO-E.

The CM modelling uses probabilistic distributions from these BID3 simulations as an input to assess the recommended capacity to secure. The CM modelling also uses BID3 to assess the contribution of interconnectors to security of supply to provide a recommendation of the de-rating factor range for each connected market. This is covered in more detail in Section 4.2. Further details on the interconnector flow modelling in FES 2020 will be provided when the document is published in the week commencing 27th July 2020.

## 3.10 Sensitivity Descriptions and Justifications

Our modelling assumes that the FES and the Base Case cover uncertainty in future electricity demand and supply. This includes uncertainty in peak demand, DSR, generation, storage and interconnection capacity.

We also model sensitivities to assess uncertainty that is not covered by the scenarios. The sensitivities cover uncertainty in over/non-delivery, station availability, weather, wind output and peak demand.[48] Sensitivities are only applied to the Base Case such that only one variable is changed at a time. Each of the sensitivities is considered credible in that it is either evidence-based (i.e. it has occurred in recent history) or it addresses statistical uncertainty caused by the small sample sizes used for some of the input variables.

Further details on the sensitivities are included below. This includes a description of what each sensitivity is, why it was included and how we modelled it with details of any relevant values. We also include details of some additional sensitivities that were considered but not included in our modelling. These sensitivities were discussed with BEIS, PTE and Ofgem and were agreed in May 2020.

[47] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite
[48] Based on the Peak National Demand Forecasting Accuracy (DFA) incentive. See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

### 3.10.1 High / Low Wind

This sensitivity covers the potential output from wind generation at times of cold weather (i.e. high demand). Our modelling assumes that the output from wind generation is lower at times of peak demand based on previous research supported by our academic consultants.[49] In the DDM, this is modelled as a scaling factor of 0.75 to align the output with that from the combined storage, wind and solar fleet EFC values. However, there is significant uncertainty in the choice of this scaling factor, justifying the inclusion of a high / low wind sensitivity.

We model the high wind sensitivity assuming the wind scaling parameter has a value of 1. This essentially assumes that there is no reduction in wind output at times of high demand and wind output is entirely independent of cold weather conditions. We model the low wind sensitivity assuming a wind scaling parameter of 0.5, chosen to set a symmetric range around our base case assumption of 0.75. This is unchanged since the 2019 ECR.

### 3.10.2 High / Low Plant Availabilities

This sensitivity covers potential uncertainty in the availability of conventional thermal generation. Conventional plant availabilities are based on the mean availability of the fleet during the winter peak period over the last 7 years. However, as this is a relatively small sample size, we cannot be confident that these mean values will be statistically representative of what could happen in the future. Inclusion of this sensitivity is justified to address this statistical uncertainty in calculating the mean availability from a small number of data points.

This sensitivity only has an impact on capacity that has already been secured for future delivery years. Therefore, it is only included in our modelling for the 2021/22 T-1 auction. There is no material impact on the analysis for the 2024/25 T-4 auction as only a small amount of capacity has already been secured for that year.

In our modelling, this sensitivity is applied to previously contracted nuclear and CCGT stations, as these represent the two largest contributing generation technologies. The high availability sensitivity assumes that the fleet availability of these technologies is 1 standard deviation above the mean availability for the last 7 years. The low availability sensitivity assumes that the fleet availability of these technologies is 1 standard deviation below the mean. The approach for this sensitivity is unchanged since the 2019 ECR. Table 11 shows the current values used for the high and low availability sensitivities in this year's modelling.

**Table 11: Availability assumptions for CCGT and nuclear technologies in the low and high availability sensitivities.**

| Technology | Low availability | High availability |
|---|---|---|
| CCGT | 87.0% | 93.0% |
| Nuclear | 76.6% | 86.3% |

[49] For example, see section 2.5 in the 2019 ECR for further information.

### 3.10.3 Cold / Warm Winter

This sensitivity covers the uncertainty on demand due to weather. Demand is highly sensitive to weather. Our modelling uses a demand history of 13 years in the LOLE calculation. As this is a relatively short history (e.g. the Met Office would typically use a longer period of 30 years or more when calculating average temperatures), we can not be confident that this will be statistically representative of future years. Therefore, the uncertainty associated with colder or warmer winters may not be fully reflected, justifying the inclusion of the sensitivity.

As in previous ECR modelling, the cold winter sensitivity is modelled by calculating the LOLE based on the weather that occurred in 2010/11. The warm winter sensitivity is modelled by calculating the LOLE based on the weather that occurred in 2006/07. This is unchanged since the 2019 ECR.

### 3.10.4 High / Low Demand

This sensitivity covers the uncertainty associated in forecasting the average cold spell (ACS) peak demand. National Grid ESO has a Demand Forecasting Accuracy (DFA) incentive with an obligation to publish the steps we take to improve our forecasts every year.

The sensitivity is modelled based on the range associated with the T-1 DFA incentive. The high demand sensitivity is modelled assuming that the ACS peak demand is 2% higher than assumed in the Base Case. The low demand sensitivity is modelled assuming that the ACS peak demand is 2% lower than assumed in the Base Case. This is unchanged since the 2019 ECR.

### 3.10.5 Non-delivery

This sensitivity covers the risk that capacity providers fail to deliver in line with their capacity market agreements (e.g. a station with an agreement closes before the delivery year or a new station is delayed). As in the 2019 ECR, this sensitivity considers different categories of non-delivery, including an allowance for market response, which are combined using a root sum of squares approach to determine the maximum non-delivery for each delivery year. A set of non-delivery sensitivities are then applied to the Base Case in steps of 0.4 GW up to the maximum non-delivery level. Steps of 0.4 GW are appropriate as they reflect the confidence interval of the LOLE calculation and provide granularity in the LWR calculation.

This year we have modelled non-delivery sensitivities up to 2.8 GW and 2.4 GW for the 2021/22 T-1 and 2024/25 T-4 auctions, respectively. Table 12 and Table 13 show the non-delivery assumptions used in our modelling, highlighting the maximum values given by the root sum of squares approach. While the approach is broadly similar to the 2019 ECR, we have now explicitly included non-delivery risk from nuclear. This reflects recent experience of the last two winters, for which two stations failed to return in full from extended outages. Our assumptions include non-delivery from one station in 2021/22 and two stations in 2024/25. The difference arises because the Base Case assumes a higher level of nuclear capacity in 2021/22, and so the de-rating factor already allows for more than one station being unavailable all winter. Therefore, including additional non-delivery would risk double-counting. This does not hold true for 2024/25, as the Base Case assumes a lower level of nuclear capacity, meaning that it is appropriate to include an extra station in the non-delivery. All other categories are unchanged since the 2019 ECR. Further details on these assumptions are provided in Annex A5.1.

**Table 12: Maximum non-delivery for the 2021/22 T-1 auction was assumed to be 2.8 GW.**

| Category | Non-delivery (GW) | Root sum of squares (GW) |
|---|---|---|
| Large thermal | 3.0 | 9.0 |
| Nuclear | 0.9 | 0.8 |
| Distributed generation | 1.0 | 1.0 |
| Unproven DSR | 0.3 | 0.1 |
| Interconnectors | 1.5 | 2.3 |
| **Sum of non-delivery** | **6.7** | **3.6** |
| Potential market response | -1.2 | -0.6 |
| **Total** | **5.5** | **2.8 (rounded to nearest 0.4)** |

**Table 13: Maximum non-delivery for the 2024/2025 T-4 auction was assumed to be 2.4 GW.**

| Category | Non-delivery (GW) | Root sum of squares (GW) |
|---|---|---|
| Large thermal | 2.0 | 4.0 |
| Nuclear | 1.8 | 3.2 |
| Distributed generation | 0.7 | 0.5 |
| Unproven DSR | 0.4 | 0.2 |
| Interconnectors | 1.5 | 2.3 |
| **Sum of non-delivery** | **6.4** | **3.2** |
| Potential market response | -1.2 | -0.6 |
| **Total** | **5.2** | **2.4 (rounded to nearest 0.4)** |

### 3.10.6 Over-delivery

This sensitivity covers the risk that market participants deliver more than what has been contracted through the Capacity Market (e.g. stations remaining open without an agreement). This sensitivity is modelled in a similar way to non-delivery, and as in the 2019 ECR, considers different types of over-delivery. This year we have modelled over-delivery sensitivities up to a maximum value of 1.6 GW for both the 2021/22 T-1 and the 2024/25 T-4 auctions. Table 14 shows the over-delivery assumptions used in our modelling, highlighting the maximum value of 1.6 GW given by the root sum of squares approach. Further details on these assumptions are provided in Annex A5.1.

**Table 14: Maximum over-delivery for both the 2021/22 T-1 and 2024/2025 T-4 auctions was assumed to be 1.6 GW.**

| Category | Over-delivery (GW) | Root sum of squares (GW) |
|---|---|---|
| Large thermal | 1.0 | 1.0 |
| Nuclear | 0.0 | 0.0 |
| Distributed generation | 1.5 | 2.3 |
| Unproven DSR | 0.3 | 0.1 |
| Interconnectors | 1.0 | 1.0 |
| **Sum of non-delivery** | **3.8** | **2.1** |
| Potential market response | -1.0 | -0.5 |
| **Total** | **2.8** | **1.6 (rounded to nearest 0.4)** |

### 3.10.7 Sensitivities Considered but Not Included

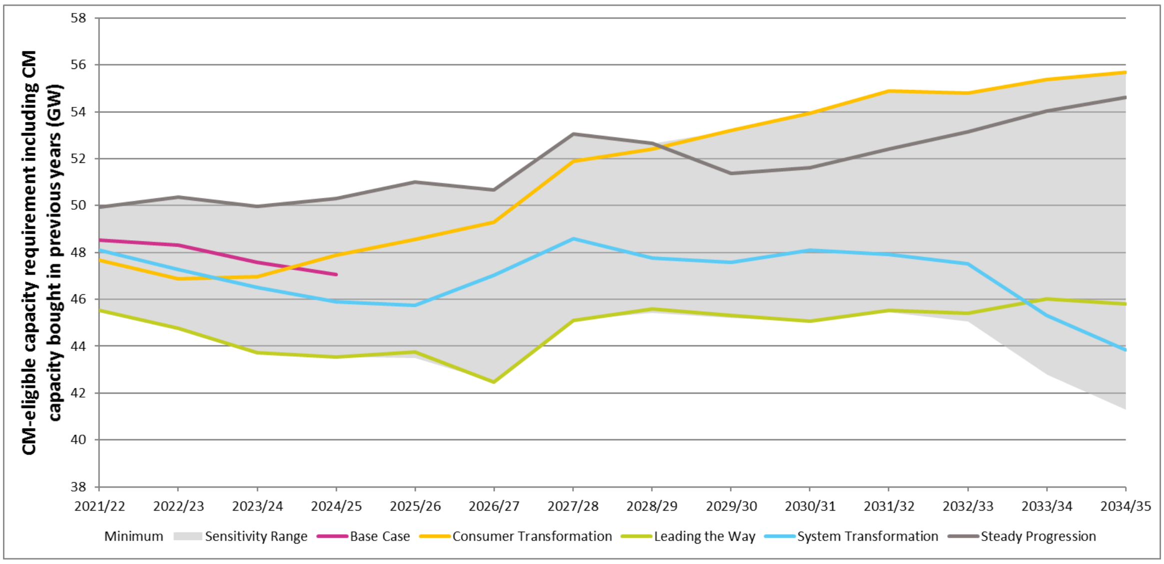
Several alternative sensitivities were considered but not included in this year's modelling. Details of these are included in the Annex A.5.2.

## 3.11 15-Year Horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2021/22 and 2024/25). It focuses on the total requirement for CM-eligible capacity and does not split each year's requirement into capacity secured in earlier years, T-1 and T-4 auctions. The requirement in 2021/22, 2022/23 and 2023/24 was derived from the 2021/22 model runs (see Chapter 5) and the capacity requirement from 2024/25 to 2034/35 from the model runs for 2024/25 (see Chapter 6). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 14 shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years. A table showing the data behind this chart can be found in Annex A.4.2

**Figure 14: Total CM-eligible Capacity required in Future Years**




The total requirement for the non-delivery and over-delivery sensitivities is the same as the Base Case. For non-delivery cases, the increase in capacity required is offset by the reduction in contracted capacity closing before the target year. Similarly, for over-delivery cases, the decrease in capacity required is compensated for by CM-eligible plants providing additional capacity without a contract.

As can be seen in Figure 14, the Consumer Transformation and Steady Progression scenarios show an increased requirement in general over the period, particularly for Consumer Transformation, driven largely by an increase in peak demand. For the System Transformation and Leading the Way scenarios the requirement remains relatively stable over most of the period, with increases in peak demand offset by increases in non-CM capacity. For System Transformation, there is a decline over the last few years resulting from an increase in low carbon capacity outside of the CM such as new nuclear. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. During the later years of the period, significant amounts of RO-supported wind farms will also come off support further increasing the CM-eligible capacity requirement in most scenarios.

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

The capacity already secured over the 15-year period can be obtained by looking in the CM registers and is summarised in the final results report for the 2023/24 T-4 auction[50]. Note that the values in this report may differ from the values calculated by the DDM for reasons such as the awarded conventional capacity from previous T-4 auctions being greater than the de-rated TEC and revisions to duration-limited storage de-rating factors from the 2020/21 T-4 auction onwards.

Figure 14 shows the level of CM capacity required to meet the Reliability Standard in all years from 2021/22. For 2020/21, we did not model the capacity requirement in each scenario / sensitivity as the T-1 capacity auction for that year has already happened. The forthcoming 2020/21 Winter Outlook Report[51] will include a view of electricity security of supply for the coming winter.

[50] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202019%20DY2023%20Capacity%20Market%20Auction%20Final%20Results%20V1.0.pdf
[51] https://www.nationalgrideso.com/research-publications/winter-outlook

# 4. De-rating Factors for CM Auctions

## 4.1 De-rating Factors for Conventional Plants, Storage and Renewables

Tables 15, 16 and 17 show the de-rating factors for conventional plants, storage and renewables, respectively. The de-rating factors cover both 2021/22 T-1 and 2024/25 T-4 auctions. 2019 de-rating factors are shown for comparison. No changes have been made to the methodology used to determine these de-rating factors since last year. Last year's de-rating factors are also shown in the table for comparison.

Conventional plant de-rating factors are calculated using the availability of transmission-connected generation during the winter peak period over the last 7 years. These de-rating factors are updated annually and further information, including details of the ranges in the low / high availability sensitivity, can be found in Annex A4.4. We should highlight that the de-rating factor for OCGT is now also used for oil. This is because the last oil-fired plant closed in 2014/15, meaning that the 7-year moving average would only include 2 years of historic data. Therefore, we recommend assigning the de-rating factor used for OCGT to oil-fired plants.

Storage de-rating factors apply to plant types that include: 'conversion of imported electricity into a form of energy which can be stored and the re-conversion of the stored energy into electrical energy. This includes hydro generating units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies'. Further details on our storage de-rating factor methodology can be found in our 2017 industry consultation.[52] Annex A.6 contains further details on the Base Case storage capacity assumptions and histograms illustrating the distribution of stress event durations for a system at 3 hours LOLE.

Renewable de-rating factors are based on the methodology[53] that was consulted with the industry in February 2019.

[52] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

[53] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf

**Table 15: De-rating factors for conventional plants. De-rating factors apply to both the 2021/22 T-1 and 2024/25 T-4 auctions. The table also includes the DSR de-rating factor which uses a different method referred to in the footnote.**

| Technology Class | Plant Types Included | ECR 2019 | ECR 2020 |
|---|---|---|---|
| Oil-fired steam generators | Conventional steam generators using fuel oil | 91.26% | 95.22% |
| Open Cycle Gas Turbine (OCGT) | Gas turbines running in open cycle fired mode | 94.98% | 95.22% |
| Reciprocating engines (non-autogen) | Reciprocating engines not used for autogeneration | 94.98% | 95.22% |
| Nuclear | Nuclear plants generating electricity | 81.22% | 81.43% |
| Hydro (excl. tidal / waves) | Generating Units driven by water, other than such units:<br>a) driven by tidal flows, waves, ocean currents or geothermal sources; or<br>b) which form part of a Storage Facility | 89.65% | 90.99% |
| CCGT | Combined Cycle Gas Turbine plants | 90.00% | 90.00% |
| CHP and autogen (provided by BEIS) | Combined Heat and Power plants (large and small-scale)<br>Autogeneration – including reciprocating engines burning oil or gas | 90.00% | 90.00% |
| Coal | Conventional steam generators using coal | 85.81% | 84.80% |
| Biomass | Conventional steam generators using biomass | 85.81% | 84.80% |
| Energy from Waste | Generation of energy from waste, including generation of energy from:<br>a) conventional steam generators using waste;<br>b) anaerobic digestion;<br>c) pyrolysis; and<br>d) gasification. | 85.81% | 84.80% |
| DSR[54] | | 86.14% | 79.21% |

**Table 16: De-rating factors for duration limited storage.**

| Duration (hours) | ECR 2019 2020/21 T-1 | ECR 2019 2022/23 T-3 | ECR 2019 2023/24 T-4 | ECR 2020 2021/22 T-1 | ECR 2020 2024/25 T-4 |
|---|---|---|---|---|---|
| 0.5 | 12.26 % | 10.59 % | 10.21 % | 12.75 % | 12.38 % |
| 1.0 | 24.70 % | 21.36 % | 20.43 % | 25.32 % | 24.77 % |
| 1.5 | 36.96 % | 31.94 % | 30.83 % | 37.71 % | 36.97 % |
| 2.0 | 48.66 % | 42.53 % | 41.04 % | 49.17 % | 48.62 % |
| 2.5 | 58.68 % | 52.18 % | 50.51 % | 58.23 % | 58.78 % |
| 3.0 | 65.93 % | 59.43 % | 57.94 % | 64.70 % | 66.18 % |
| 3.5 | 70.38 % | 64.07 % | 62.77 % | 68.76 % | 70.98 % |
| 4.0 | 72.98 % | 67.04 % | 65.93 % | 71.35 % | 73.76 % |

[54] Details of the DSR De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf

<table>
<tr><td>4.5</td><td>75.03 %</td><td>69.27 %</td><td>68.16 %</td><td>73.20 %</td><td>75.79 %</td></tr>
<tr><td>5.0</td><td rowspan="2">95.08%</td><td>71.13 %</td><td>70.20 %</td><td rowspan="2">94.64 %</td><td rowspan="2">94.64 %</td></tr>
<tr><td>5.5+</td><td>95.08 %</td><td>95.08 %</td></tr>
</table>

**Table 17: De-rating factors for renewables.**

| Technology Class | ECR 2019 2020/21 T-1 | ECR 2019 2022/23 T-3 | ECR 2019 2023/24 T-4 | ECR 2020 2021/22 T-1 | ECR 2020 2024/25 T-4 |
|---|---|---|---|---|---|
| Onshore Wind | 8.98% | 8.20% | 7.42% | 8.01 % | 7.81 % |
| Offshore Wind | 14.45% | 12.30% | 10.55% | 12.11 % | 11.13 % |
| Solar PV | 2.34% | 3.13% | 3.22% | 2.54% | 2.34 % |

### 4.1.1 Feedback on Methodologies

National Grid ESO has used the current approach to determine station availabilities and de-rating factors for the last few years. While both formal (e.g. on storage and renewable de-rating factors) and informal (e.g. discussions at industry workshops and bilateral meetings) consultations have been held, it is important that all stakeholders have an opportunity to engage in this process. This will help National Grid ESO understand any concerns that stakeholders may have regarding our approach and help to inform any future changes to the methodologies. Therefore, National Grid ESO continues to welcome comments and questions on our approaches either through email (emrmodelling@nationalgrid.com), industry forums or bilateral meetings. Any changes to de-rating factor methodologies will require consultation with industry.

We would particularly appreciate any feedback on our developing work on constrained hybrid sites (described in Section 2.5.2) and how we calculate de-rating factors for distribution-connected generation.

In our current methodology, conventional plant de-rating factors are calculated using the availability of transmission-connected units during the winter peak period. These de-rating factors are also assigned to distribution-connected generation for the relevant technology type as we do not have access to data to calculate de-rating factors for distributed generation directly. In recent years, National Grid ESO has taken steps to obtain better data and improve our modelling of distributed generation.

We have already procured metered hourly generation output data from Electralink. However, this does not provide information on the asset. We have therefore been supporting a Change Proposal to the Distribution Connection and Use of System Agreement (DCUSA) to create a register of embedded assets. This modification is referred to as DCP 350 and further information can be found on the DCUSA website.[55] We expect this data to become available in July 2020 and we are intending to review how we could use it with the Electralink data to directly calculate de-rating factors for distributed generation.

[55] https://www.dcusa.co.uk/group/dcp-350-working-group/

## 4.2 Interconnectors

Interconnectors are eligible to participate in both the 2021/22 T-1 and 2024/25 T-4 auctions except where they already have been awarded a Capacity Market agreement. The future of potential flows through interconnectors is very complex and, consequently, there is no single answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid ESO, in agreement with BEIS and the PTE, has considered in determining an appropriate de-rating factor range for each country so the Secretary of State can then decide the factors to apply to individual interconnectors.

### 4.2.1 Methodology

The participation of interconnectors in the Capacity Market is likely to be superseded by direct participation of cross-border capacity as set out in Article 26 of Regulation (EU) 2019/943 as part of the Clean Energy Package. The European Network of Transmission System Operators for Electricity (ENTSO-E) have a mandate to develop a methodology to enable this. Further information on ENTSO-E's work can be found on their website.[56] This methodology will also include a modelling approach to determine the maximum entry capacity for cross-border participation in Capacity Markets. This modelling methodology has many similarities with our interconnector modelling, and we will be working closely with ENTSO-E to support and provide input to this work, which is due to be finalised in 2021. We expect to implement this methodology in our ECR modelling when it becomes available.

In previous years, there were two elements to the methodology for informing interconnector de-rating factors: an analysis of historical flows and price differentials between the two markets and stochastic modelling of the future European electricity market. Last year, BEIS introduced changes to the interconnector de-rating methodology, removing the requirement for de-rating factors to be constrained by a historical 'floor'. Like the 2019 ECR, this year's report will therefore only cover our modelling of the future European electricity market.

Since the first ECR in 2014, National Grid ESO have continuously improved our modelling of European markets to assess the contribution from interconnectors at times of system stress. This has seen a significant change from our early 'net float' assumptions to procuring a pan-European market model and developing in-house expertise. This year is no exception and we have taken steps to further improve our modelling methodology. We published an early view of the proposed changes to our modelling in April 2020.[57] Several respondents shared their feedback with us as well as the PTE. We are very appreciative of the feedback that we received and have provided details in Chapter 1.3 on how we intend to engage further on this. As indicated in our April publication, the two main modelling changes are:

1. How we use stress periods in our modelling
2. Improved model functionality to carry out more detailed analysis of stress periods

[56] https://consultations.entsoe.eu/markets/proposal-for-cross-border-participation-in-capacit/

[57] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Modelling%20de%20rating%20factor%20ranges%20for%20interconnected%20countries%20in%20the%20CM%20in%20the%202020%20Electricity%20Capacity%20Report%20v1.pdf

We use our pan-European market model, BID3 developed by Afry[58], to simulate electricity markets across Europe to assess potential interconnector flows from connected countries across different scenarios at times of system stress in Great Britain. This allows us to assess the impact of around 30 years of correlated weather conditions, in combination with different generation and demand outlooks for neighbouring markets.

A system stress event occurs when the expected unserved energy is greater than zero.[59] In previous years, our de-rating factor ranges for interconnected countries have been based on analysis of interconnector flows to Great Britain at times when demand in Great Britain was higher than available generation located in Great Britain (i.e. interconnector imports are needed to prevent a loss of load event).

However, this may not strictly lead to unserved energy and available capacity from Europe may mean that a stress event could be avoided in these periods. Therefore, in this year's analysis we have extended our modelling such that our interconnector analysis only includes periods when the expected energy unserved is greater than zero. Essentially, this means that our interconnector de-rating factor ranges is now only based on periods for which we expect demand in Great Britain to be higher than available supply including imports.

This approach brings our modelling closer to the definition of a stress event in the Capacity Market rules. It also offers greater alignment with the methodology used to calculate de-rating factors for limited duration storage and renewables. It is also consistent with the principles that ENTSO-E have already set out in the aforementioned methodology.[60]

In previous years, we have undertaken our interconnector modelling using full, highly detailed annual dispatch simulations. These runs simulated generation and demand across Europe for each hour in the year with a full 30-year weather history. We then filtered on the tightest periods to assess the interconnector flow at times of system stress. In 2019, we refined this approach to target the 90 tightest periods to be consistent with the Reliability Standard of 3 hours LOLE. However, this ultimately means that less than 0.1% of the hours that we modelled were being used to inform the de-rating factor ranges, which is inefficient.

New functionality has been developed in BID3 to identify the tightest periods at the outset. We can then dedicate our modelling resource to only simulating the hours around these periods of interest rather than simulating every hourly period in the year. This means we can study the relevant periods in much more detail than we have previously done. This has been delivered through a new module in BID3 – referred to as the 'LOLE module' – which has been developed by Afry and tested by National Grid ESO.

[58] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite

[59] See Section 8.4.1 of the Capacity Market Rules: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/822019/Informal_Consolidation_of_Capacity_Market__Rules_July_2019.pdf

[60] See Article 5 in: https://consultations.entsoe.eu/markets/proposal-for-cross-border-participation-in-capacit/supporting_documents/ENTSOE%20Proposal%20for%20crossborder%20participation%20in%20capacity%20mechanisms%20%20for%20public%20consultation.pdf

This approach presents two further modelling opportunities that we could not explore previously. We can now:

1. Better assess the impact of generation availability in Europe
2. Explore the impact of potential changes to the supply and demand outlook in Europe through sensitivities.

### Impact of generation availability in Europe

In BID3, every unit is assumed to have an availability expressed as a percentage to reflect that there will be periods when a generator will not be available (e.g. forced outage). In our full dispatch simulations, a 1 GW unit with availability of 90% would be assumed to have 900 MW available capacity for 100% of the time. The new approach means that this same unit is now modelled as having 1 GW capacity available for 90% of the time and zero availability for 10% of the time, determined randomly.

This approach is applied to every unit in a market to create an outage pattern for each market. We can then repeat this again and again to create multiple outage patterns for each market. Outage patterns for each market are then randomly selected and combined to create an outage case for all of Europe. Because the simulations are now much quicker as we are only focussing on the stress periods, we can model the stress periods with multiple outage cases for Europe (e.g. up to around 1000 different cases[61]). For each scenario, we model, we can determine a de-rating factor by taking an average of the flows across all stress periods and outage cases.

This approach means we can better assess the range of available generation. There will be some cases with higher than average availability and some with lower availability. This better reflects the reality of the market and is consistent with our modelling for the target capacity in the ECR using the Dynamic Dispatch Model (DDM).

## 4.2.2 European Sensitivities

Our supply and demand assumptions for Europe are based on scenarios developed by ENTSO-E and other European TSOs. Details of the sources used in our current assumptions are published in the Future Energy Scenarios (FES) Modelling Methodology and the 2019 ECR.[62] While we have not changed our sources for this year's analysis, we have had to realign the European assumptions to reflect the change to the FES Scenario Framework. In our 2020 ECR modelling, Steady Progression uses the same European assumptions as the Steady Progression scenario from FES 2019. All other scenarios in our 2020 ECR modelling assume the same European assumptions as the Two Degrees scenario from FES 2019.

The supply and demand outlook for Europe is uncertain. The reduced simulation time in our new modelling approach means that we can assess the impact of potential uncertainty that is not covered by the European scenario assumptions through sensitivity analysis.

Table 18 shows the sensitivities modelled. Note that the sensitivities carried out cover a wide range, only one point in this range is selected for presentation in the results presented

[61] We used 1000 cases in our 2020 ECR analysis
[62] http://fes.nationalgrid.com/media/1417/fes-modelling-methods-2019.pdf and https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

in this chapter. It is worth highlighting that the new modelling functionality has allowed us to model significantly more cases than in previous ECR analysis. For each auction year, we have modelled five scenarios (Base Case + FES 2020) with around 100 sensitivities each. Each scenario and sensitivity has been modelled with 1000 different outage cases, effectively giving around 500,000 simulations per auction year. Previously, we were only able to model around 20 simulations per auction year.

**Table 18: European Scenario Sensitivities**

| Sensitivity Name | Description | Justification |
|---|---|---|
| Ireland Thermal | Scaling thermal plant capacity in Ireland from 100% to 0% in 10% steps | Ireland has low levels of interconnection, any change in thermal capacity will have a large effect on the de-rating factor |
| France Nuclear | Reducing nuclear plant capacity in France from -0GW to -20GW in 2GW steps | France relies heavily on nuclear power and has high electricity demand. Recent history has shown that type faults can remove a large amount of capacity for extended periods |
| Belgium Nuclear | Scaling nuclear plant capacity in Belgium from 100% to 0% in 10% steps | Belgium is due to phase out its nuclear fleet, any plant failures may result in the aging plant not returning to the market |
| Netherlands Thermal | Scaling thermal plant capacity in Netherlands from 100% to 0% in 10% steps | Netherlands has significant coal capacity which may be phased out due to environmental concerns |
| Germany Coal | Scaling coal plant capacity (including CHP) in Germany from 100% to 0% in 10% steps | Germany is taking a phased approach to reducing coal capacity. Environmental concerns may accelerate this process |
| Denmark Thermal | Scaling thermal plant capacity in Denmark from 100% to 0% in 10% steps | Denmark has coal capacity which may be phased out ahead of schedule due to environmental concerns |
| **Sensitivities simulated, but not considered in the results** | | |
| European Demand | Demand in all modelled European markets increased by 2% to 20% in 2% steps | The level of peak demand is critical for determining the spare capacity in a given market. If electrification occurs at a faster rate than forecast this may result in significantly higher peak demand. |
| Norway Hydro | Scaling hydro plant capacity in Norway (simulating a lack of water rather than closure of the plant) from 100% to 0% in 10% steps | Although the 31 weather years should cover a range of hydro inflow, it is possible that these years do not cover all possible inflow levels. |
| European Thermal | Scaling all thermal plant in all modelled European markets from 100% to 90% in 1% steps | Rather than considering a sensitivity that only affects one market this sensitivity makes a smaller change, but in all markets |
| Intra-Europe Interconnector Outages and Losses | Including interconnector outages for interconnectors between European markets (not including Great Britain to Europe). Also considering varying AC interconnector losses | Interconnectors in BID3 use a deterministic availability factor that reduces capacity. This can be changed to model discrete outages. Varying the AC interconnector loss level will affect the path that electricity will take across Europe and therefore which interconnector it arrives in Great Britain from |
| Germany CCGT Increase | Increasing Germany CCGT plant capacity from 0 to 10GW in 1GW steps | Scenario forecasts may underestimate the closure rate of conventional thermal plant in Germany as the market decarbonises |

| | | |
|---|---|---|
| Scenario Interconnector Capacity | Removing interconnectors that have not taken final investment decision from Leading the Way | Interconnectors included in the 2024/25 delivery year which have not yet taken final investment decision may not be commissioned in time |

Our interconnector analysis requires us to provide a range for each interconnected country. The upper end of the range was set by the supply and demand assumptions in our European scenarios. These assumptions show that there is currently a surplus of capacity in Europe with many countries reporting LOLE values lower than their Reliability Standards.[63] This would indicate limited potential for additional capacity being needed as security of supply has already been met and so we have modelled this for the top end of our range.

However, there is considerable scope in choosing the sensitivity that sets the lower end of the range. As in the DDM sensitivities, it is important that this is evidence-based. This ultimately led to two approaches. The first approach was based on reducing the surplus capacity in Europe to bring the LOLE closer to 3 hours (or 8 hours in Ireland). This may be considered credible on the basis that as European countries introduce capacity mechanisms, the additional capacity will not be required and so will close. The second approach was based on recent experience of high nuclear outages in France during winters 2016/17, 2017/18 and 2019/20. Nuclear generation can be prone to type faults and as this was observed in a recent winter, we believe it's a credible risk to reflect in our modelling.

There is currently no consensus or consistency in the approach to Reliability Standards in Europe. For example, some countries have a Reliability Standard, while other do not (e.g. Germany). Of those that have a Reliability Standard, Great Britain, France and Belgium use 3 hours LOLE, while Ireland has a Reliability Standard of 8 hours LOLE.[64] This lack of consistency is expected to change in line with Article 23 of Regulation (EU) 2019/943, which will seek to harmonise the methodology, which is being developed by ENTSO-E.[65] The proposals based on defining the Reliability Standard based on LOLE as the ratio of CONE / VoLL is consistent with the approach already used in Great Britain and now subject to approval by ACER.[66] This is expected to be phased in over the next few years. Given the harmonisation of the approach, this could lead to countries adopting similar Reliability Standards. We assumed 3 hours in our modelling for mainland Europe to be consistent with that already established in Great Britain, Belgium and France. Ireland is only connected to Great Britain and was modelled with the higher value of 8 hours LOLE to be consistent with its Reliability Standard.

Each sensitivity in Table 18 consists of a number of discrete points, all of which are simulated for each scenario and delivery year. Therefore, for each sensitivity a level must be chosen which is deemed to be credible. To determine this level simulations were run in BID3 where all thermal plant in all modelled markets was scaled down in increments. The loss of load expectation (LOLE) was calculated for each market and thermal scaling level. The credible threshold was determined to be the point at which the LOLE just exceeded 3 hours average, except for Ireland which was 8 hours. The level of scaling determined a MW capacity that could be removed from the market whilst respecting the security standard of the market. This MW capability figure was then applied to each sensitivity to determine a credible threshold for each sensitivity.

[63] For example, ENTSO-E 2019 Mid-term Adequacy Forecast report: https://www.entsoe.eu/outlooks/midterm/
[64] For example, GB, Belgium and France have 3 hours LOLE. Ireland has a Reliability Standard of 8 hours LOLE (although Northern Ireland is 4.9 hours LOLE). Netherlands uses 4 hours LOLE and some countries such as Germany do not have a Reliability Standard.
[65] https://consultations.entsoe.eu/entso-e-general/proposal-for-voll-cone-and-reliability-standard-me/
[66] https://www.acer.europa.eu/m/news/Pages/News-Details.aspx?ItemId=418

### France Nuclear Additional Sensitivity

Recent history has shown that the large nuclear fleet in France is susceptible to type faults. There have been several instances where around 10 GW of nuclear plant has been on long term unplanned outage during the winter months (for example Dec 2016, Dec 2017, Dec 2019 and Jan 2020).[67] This historic loss of capacity is beyond the level assumed for either delivery year when the sensitivity capacity scaling threshold for an LOLE in France of 3 hours was determined. Therefore, a sensitivity of 10 GW loss of nuclear capacity in France is included.

The sensitivity that gives the lowest de-rating factor for each market is shown in the results tables and figures as the 'most onerous sensitivity'. The sensitivity, excluding the France nuclear additional sensitivity (i.e. only those shown in Table 18) is shown in the results tables and figures as the 'European LOLE standard'. The France nuclear additional sensitivity is shown as the 'France Nuclear -10GW'.

Like previous years, strategic reserves held outside the market in neighbouring countries have also not been included in our modelling. This is because we do not believe they could be deployed to support adequacy in Great Britain due to conditions of State Aid approval.

**Table 19: Pan-European modelling runs**

| Scenarios | Graph name | Description |
|---|---|---|
| Average of FES scenarios | Average | Average of de-rating factors for BC, CT, ST, LW & SP |
| Base Case | BC | 2020 Future Energy Scenarios – Base Case |
| Consumer Transformation | CT | 2020 Future Energy Scenarios – Consumer Transformation |
| System Transformation | ST | 2020 Future Energy Scenarios – System Transformation |
| Leading the Way | LW | 2020 Future Energy Scenarios – Leading the Way |
| Steady Progression | SP | 2020 Future Energy Scenarios – Steady Progression |

## 4.2.3 BID3 Pan-European Model Results

The imports as a percentage of interconnector capacity, from all the pan-European simulations, are shown in Table 20 for 2021/22 and Table 21 for 2024/25. Where there are 'N/A' in these tables, that country is not connected to Great Britain in that scenario and delivery year. Interconnectors to Denmark, Germany and Norway do not appear in the results for 2021/22 as no interconnectors are assumed to connect to these markets in any of the scenarios for 2021/22. De-rating factors are not calculated for France, Belgium or the Netherlands for 2021/22 as all interconnectors forecast to connect by this delivery year already have a Capacity Market contract for 2021/22.

The FES results use FES forecasts for Great Britain and the closest scenario for the rest of Europe. GB demands were increased significantly (by scaling the demand) to ensure that

[67] French nuclear capacity is 63 GW. Extended French nuclear outages meant availability in winter 2016/17 was low. Available nuclear capacity was around 50 GW or lower in December 2016, slowly rising to around 55 GW by late January 2017. In addition nuclear output was also low in December 2017 (around 50 GW) and winter 2019/20 (typically below 50 GW). Based on nuclear generation output data available on RTE's website: https://www.rte-france.com/en/eco2mix/eco2mix-mix-energetique-en.

there was load loss in all simulated time periods. The 93 time periods with the most load loss were simulated in BID3. This is an average of 3 hours LOLE across 31 weather years.

Each of the results tables contains results for the 5 scenarios and the most onerous sensitivity (i.e. the sensitivity that results in the lowest de-rating factor) from all of the sensitivities for each of the scenarios. Note that the most onerous sensitivity may vary for each scenario.

**Table 20: Simulation results: 2021/22 imports as percentage of interconnector capacity**

| Country | ECR 2019 2020/21 T-1 | | Scenarios | | | | | | Most onerous sensitivity | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Min. | Max. | Average | BC | CT | ST | LW | SP | Average | BC | CT | ST | LW | SP |
| Ireland | N/A | N/A | 99 | 99 | 99 | 99 | 98 | 99 | 55 | 58 | 54 | 57 | 53 | 56 |

**Table 21: Simulation results: 2024/25 imports as percentage of interconnector capacity**

| Country | ECR 2019 2023/24 T-4 | | Scenarios | | | | | | Most onerous sensitivity | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Min. | Max. | Average | BC | CT | ST | LW | SP | Average | BC | CT | ST | LW | SP |
| Ireland | 24 | 32 | 52 | 50 | 52 | 50 | 44 | 66 | 29 | 33 | 36 | 33 | 19 | 24 |
| France | 57 | 79 | 89 | 91 | 91 | 91 | 85 | 86 | 54 | 59 | 57 | 59 | 45 | 50 |
| Belgium | 38 | 56 | 83 | 88 | 87 | 87 | 71 | 80 | 49 | 54 | 53 | 54 | 39 | 46 |
| Netherlands | 30 | 44 | 78 | 84 | 84 | 84 | 63 | 77 | 46 | 49 | 48 | 49 | 34 | 48 |
| Germany | N/A | N/A | 83 | N/A | N/A | N/A | 83 | N/A | 54 | N/A | N/A | N/A | 54 | N/A |
| Denmark | 35 | 35 | 69 | N/A | 80 | N/A | 59 | N/A | 39 | N/A | 45 | N/A | 32 | N/A |
| Norway | 93 | 99 | 100 | 100 | 100 | 100 | 100 | 99 | 95 | 96 | 96 | 96 | 96 | 91 |

## 4.2.4 Country de-ratings

The results for each scenario averages are shown in Figure 15 to Figure 22 and Table 22 to Table 31. **The modelled de-rating factor ranges do not include an allowance for technical de-rating.**

As this methodology is based around the modelling of European markets, step changes in results could potentially occur between years due to changes in demand, generation mix and the resulting capacity margin. A problem in one country can impact flows from surrounding countries, as can be seen by the impact of German nuclear closures on Belgium and Netherlands interconnector flows. Modelling flows across Europe for the auction year gives confidence that these interactions have been reflected in the modelled range of de-rating factors.

The FES scenarios for 2021/22 have high margins for GB. This is a combination of new generation, with CM contracts in later years, being completed early and some unsuccessful generation without CM contracts staying online to compete for capacity payments in later years. This means that in all scenarios, there are very few hours that meet the low margin criteria for calculating de-rating factors. Therefore, for interconnector de-rating modelling only, the GB demand forecasts have been increased to narrow margins in Great Britain and produce the number of stress periods that would be expected if the LOLE was 3 hours.

European margins are falling over the next few years. This along with increased interconnector capacity has a downward pressure on interconnector de-rating factors in 2024/25 when compared to 2021/22. The electricity networks of continental Europe are all highly interconnected. This level of interconnection increases for 2024/25 compared to 2021/22.

### Ireland:

The modelled ranges for Ireland are 53% to 99% for 2021/22 and 19% to 52% for 2024/25.

Ireland is a single energy market economically but currently there are limited physical links between the north and south. This is expected to be rectified with an additional North/South link, planned to be commissioned in 2023. Ireland was modelled as a single price area assuming no restrictions on flows within the all-island system. Our modelling assumes an import capacity on Moyle of 500 MW in all scenarios and years except one scenario (Steady Progression) where we assumed an import capacity of 250 MW in 2021/22[68] and 500 MW in 2024/25.

Eirgrid is forecasting there will be downward pressure on generation in its 2019 All-Island Generation Capacity Statement[69]. This is partly due to the Irish Capacity Market currently targets 8 hours LOLE through Capacity Market auctions.

No results are shown for the France nuclear additional sensitivity because Ireland does not have any interconnection to France except via Great Britain (Great Britain will not export during stress events).

[68] The current interconnector register assumes 160 MW import capacity for Moyle in winter 2021/22 but depending on the system conditions, it may be possible to flow higher imports

[69] http://www.soni.ltd.uk/media/documents/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

**Figure 15: Irish interconnector de-rating factors 2021/22**

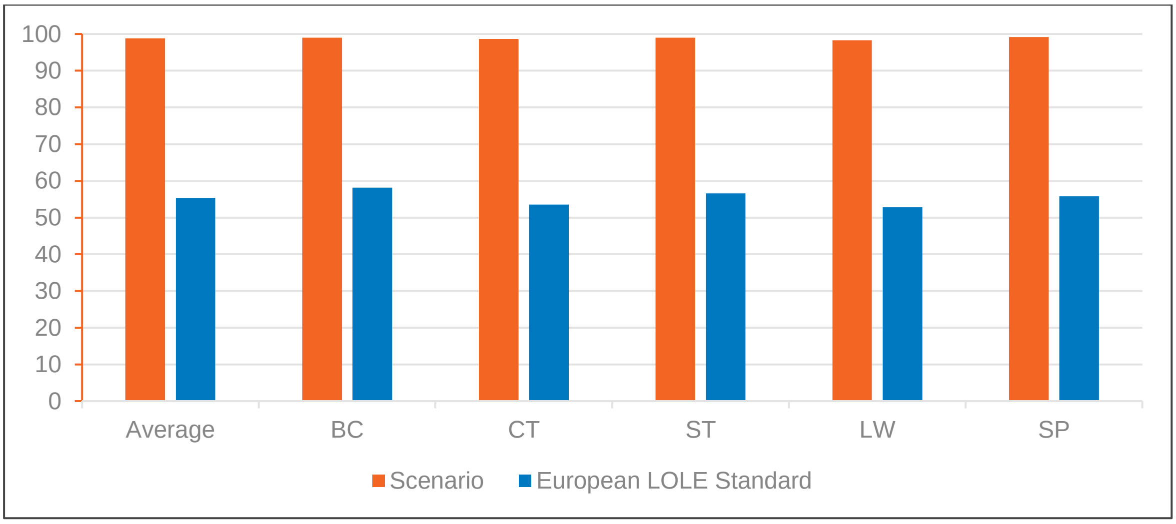



**Table 22: Irish interconnector de-rating factors 2021/22**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 99 | 99 | 99 | 99 | 98 | 99 |
| Most onerous sensitivity | 55 | 58 | 54 | 57 | 53 | 56 |
| | N/A | Ireland Thermal | Ireland Thermal | Ireland Thermal | Ireland Thermal | Ireland Thermal |

**Figure 16: Irish interconnector de-rating factors 2024/25**

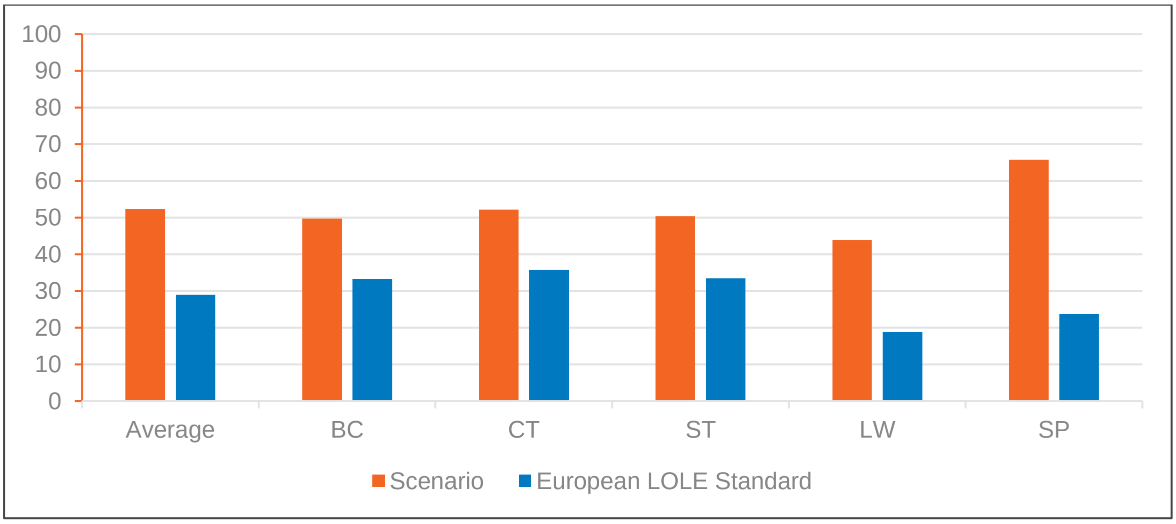



**Table 23: Irish interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 52 | 50 | 52 | 50 | 44 | 66 |
| Most onerous sensitivity | 29 | 33 | 36 | 33 | 19 | 24 |
| | N/A | Ireland Thermal | Ireland Thermal | Ireland Thermal | Ireland Thermal | Ireland Thermal |

## France:

The modelled ranges for France are 45% to 91% for 2024/25. The French generation margin is generally positive, although French demand is very weather sensitive, so very cold weather results in demand exceeding domestic generation. As the interconnector capacity with France grows and nuclear capacity is curtailed, we may see de-rating factors falling in the future. France is well interconnected to other markets in Europe.

**Figure 17: French interconnector de-rating factors 2024/25**

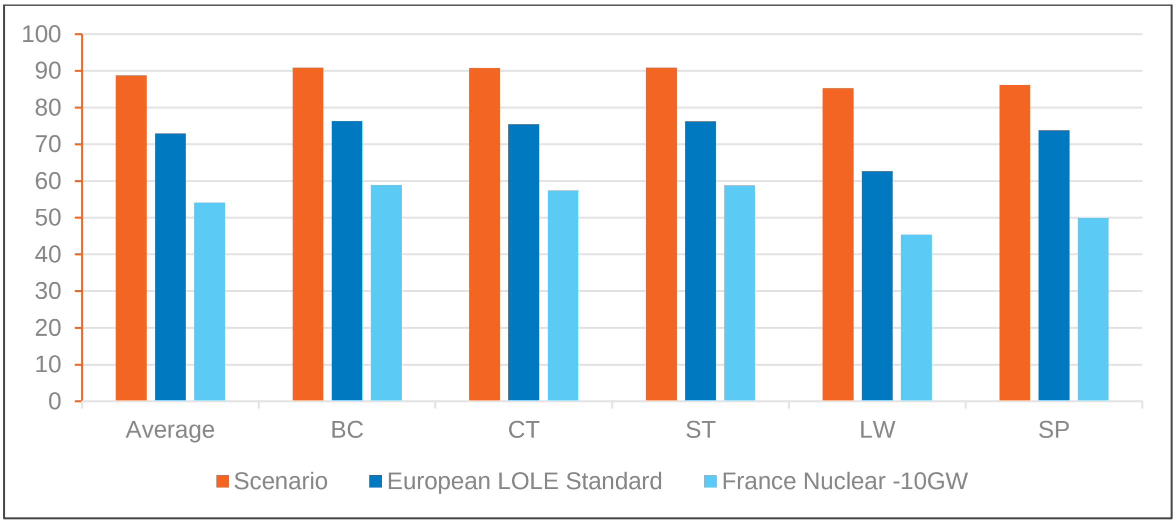



**Table 24: French interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 89 | 91 | 91 | 91 | 85 | 86 |
| European LOLE Standard | 73 | 76 | 75 | 76 | 63 | 74 |
| France Nuclear -10GW | 54 | 59 | 57 | 59 | 45 | 50 |
| Most onerous sensitivity | 54 | 59 | 57 | 59 | 45 | 50 |
| | N/A | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW |

## Belgium:

The modelled ranges for Belgium are 39% to 88% for 2024/25. Belgium plans to phase out nuclear power by 2025, this is the justification for carrying out the Belgium nuclear sensitivity.

**Figure 18: Belgium interconnector de-rating factors 2024/25**

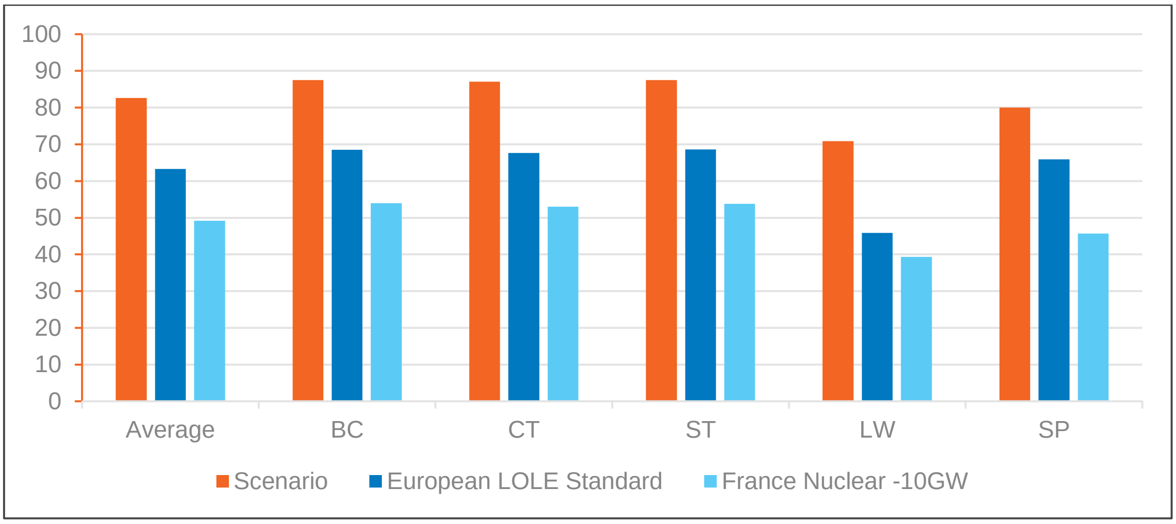



**Table 25: Belgium interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 83 | 88 | 87 | 87 | 71 | 80 |
| European LOLE Standard | 63 | 69 | 68 | 69 | 46 | 66 |
| France Nuclear -10GW | 49 | 54 | 53 | 54 | 39 | 46 |
| Most onerous sensitivity | 49 | 54 | 53 | 54 | 39 | 46 |
| | N/A | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW |

## Netherlands:

The modelled ranges for Netherlands are 34% to 84%.

The modelling assumed a firm import capacity of 1000 MW and the de-rating factor range is based on this capacity. The maximum historical imports have been 1200 MW although this can only be sustained for a very short time and so is not considered firm.

**Figure 19: Netherlands interconnector de-rating factors 2024/25**

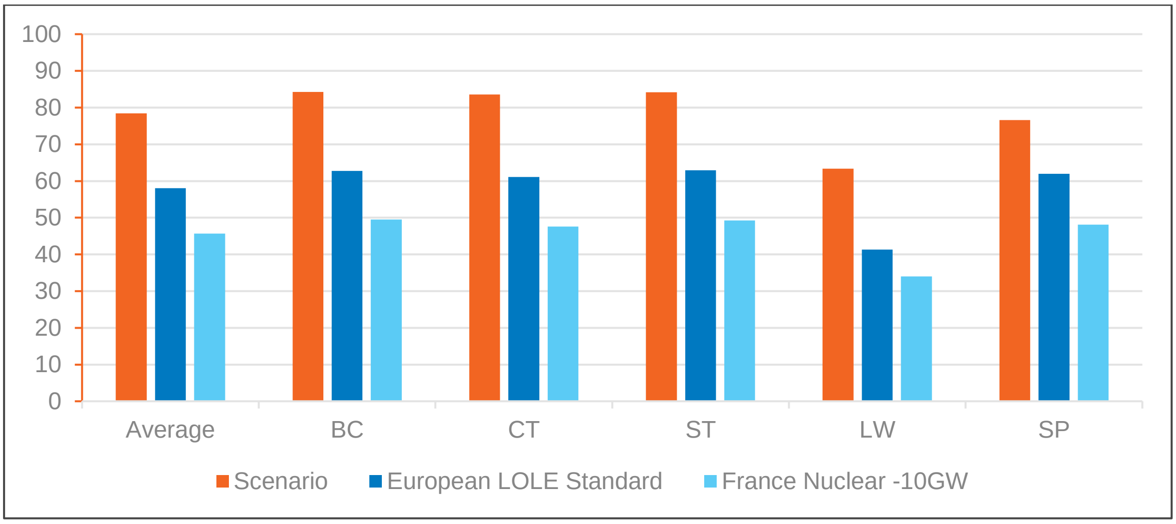



**Table 26: Netherlands interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 78 | 84 | 84 | 84 | 63 | 77 |
| European LOLE Standard | 58 | 63 | 61 | 63 | 41 | 62 |
| France Nuclear -10GW | 46 | 49 | 48 | 49 | 34 | 48 |
| Most onerous sensitivity | 46 | 49 | 48 | 49 | 34 | 48 |
| | N/A | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW |

## Germany:

Interconnectors to Germany only appear in the Leading the Way scenario for 2024/25. The modelled ranges for Germany are 54% to 83%.

**Figure 20: Germany interconnector de-rating factors 2024/25**

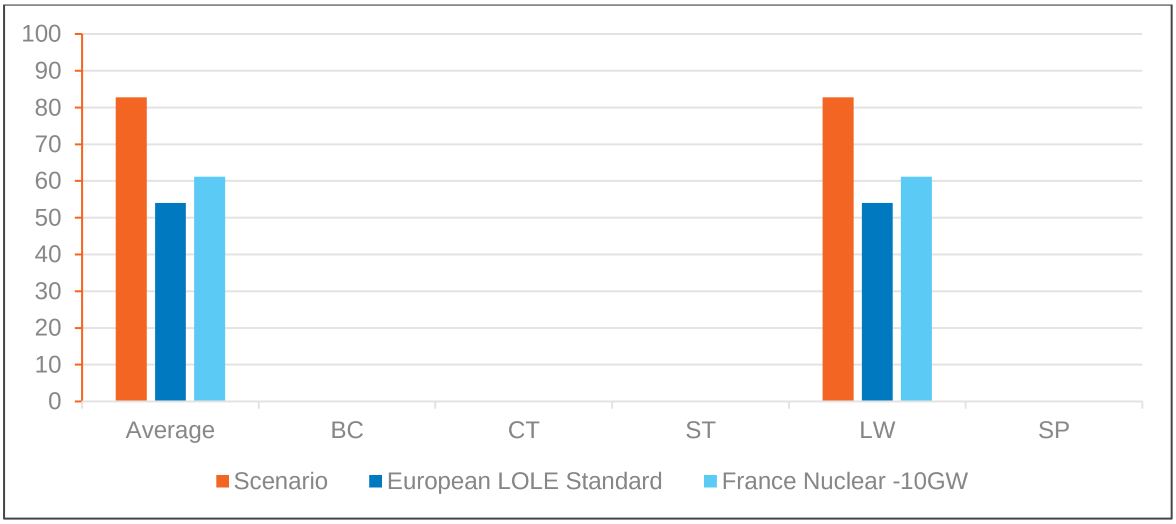



**Table 27: Germany interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 83 | N/A | N/A | N/A | 83 | N/A |
| European LOLE Standard | 54 | N/A | N/A | N/A | 54 | N/A |
| France Nuclear -10GW | 61 | N/A | N/A | N/A | 61 | N/A |
| Most onerous sensitivity | 54 | N/A | N/A | N/A | 54 | N/A |
| | N/A | N/A | N/A | N/A | Germany Coal | N/A |

## Denmark:

Interconnectors to Denmark only appear in the Leading the Way and Consumer Transformation scenarios for 2024/25. The modelled ranges for Denmark are 32% to 80%.

**Figure 21: Denmark interconnector de-rating factors 2024/25**

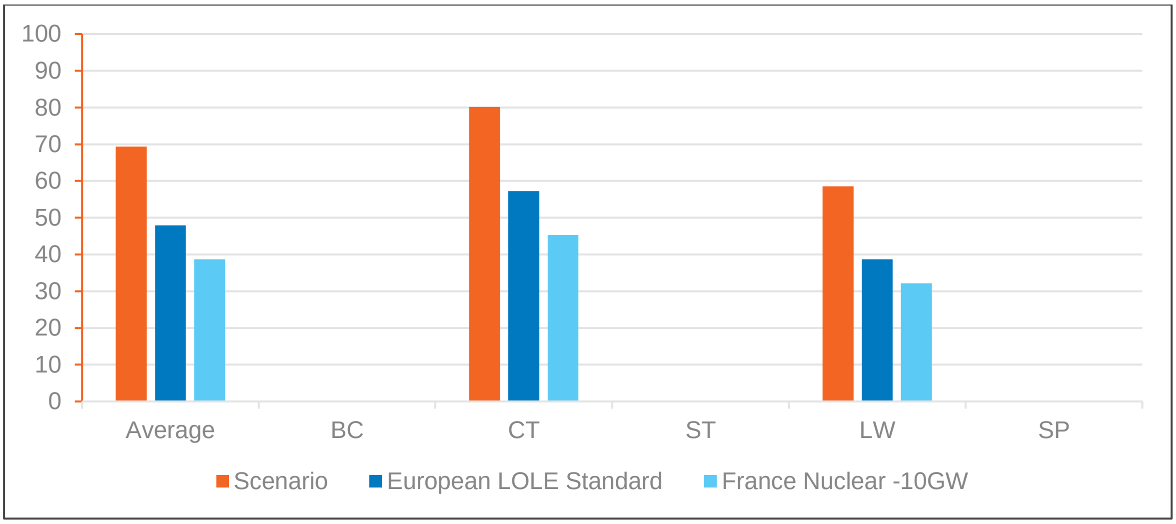



**Table 28: Denmark interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 69 | N/A | 80 | N/A | 59 | N/A |
| European LOLE Standard | 48 | N/A | 57 | N/A | 39 | N/A |
| France Nuclear -10GW | 39 | N/A | 45 | N/A | 32 | N/A |
| Most onerous sensitivity | 39 | N/A | 45 | N/A | 32 | N/A |
| | N/A | N/A | France Nuclear -10GW | N/A | France Nuclear -10GW | N/A |

## Norway:

The modelled ranges for Norway are high across all scenarios giving a range of 91% to 100% for 2024/25. This is due to the large volume of hydro capacity in Norway.

**Figure 22: Norway interconnector de-rating factors 2024/25**

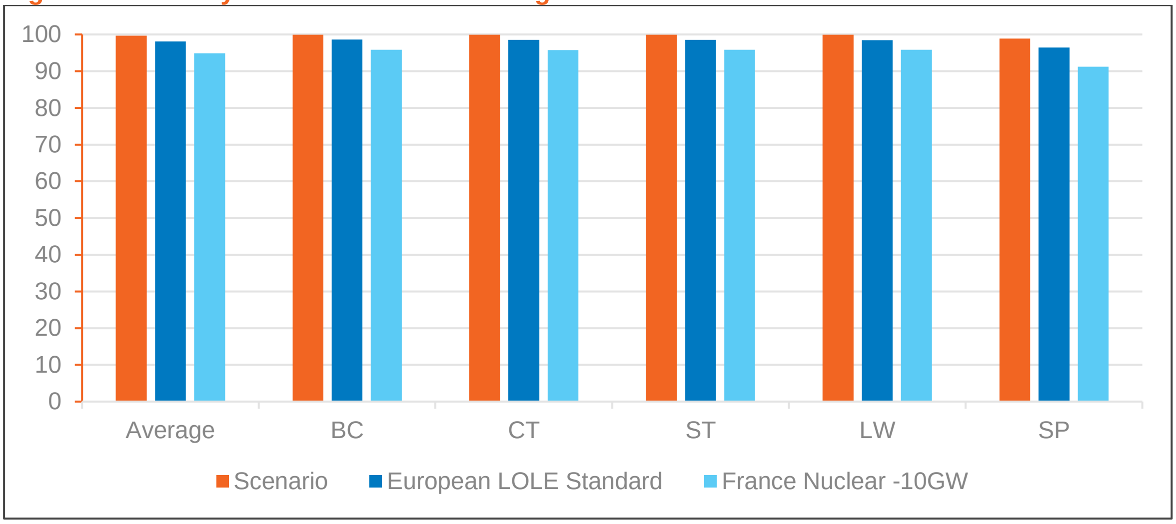



**Table 29: Norway interconnector de-rating factors 2024/25**

| Calculation | Average | BC | CT | ST | LW | SP |
|---|---|---|---|---|---|---|
| Scenario | 100 | 100 | 100 | 100 | 100 | 99 |
| European LOLE Standard | 98 | 99 | 99 | 99 | 98 | 96 |
| France Nuclear -10GW | 95 | 96 | 96 | 96 | 96 | 91 |
| Most onerous sensitivity | 95 | 96 | 96 | 96 | 96 | 91 |
| | N/A | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW | France Nuclear -10GW |

## Summary

This year, it has not been possible to use the FES scenario data without adjusting demand in Great Britain due to the lack of stress periods in Great Britain. BID3 is an economic model so if Great Britain has a surplus of generation the model will export and not import. Furthermore, if the volume of loss of load is less than the available interconnection capacity then BID3 will chose the cheapest market to source the electricity from. Therefore, demand in Great Britain was increased to ensure that enough stressed periods were available to represent 3 hours LOLE. As a 31-year history was modelled this is 3 hours * 31 years = 93 hours.

The range has been selected from the maximum and minimum of the results from the 93-hour demand uplift (see Table 30). The maximum will be set by the results for one of the Future Energy Scenarios. The minimum is likely to be set by one of the sensitivities. However, the majority of the minima are set by one of the Leading the Way sensitivities and it is noticeable that the results for the Leading the Way sensitivities appear to be an outlier. The results in Table 31 exclude Leading the Way and associated sensitivities. The minimum value increases, often significantly, in all markets with the exception of Ireland for the 2021/22 delivery year.

The reason for this is that Leading the Way is the only scenario that includes interconnectors that have not started construction or taken a final investment decision (FID) yet. Therefore, the de-rating factors are based on the assumption that there is 15.1 GW interconnector capacity between Great Britain and Europe. Great Britain currently has 9.8 GW interconnection that is either operational or under construction / taken FID. The higher capacity assumed in Leading the Way dilutes the de-rating factors.[70] Recent experience suggests that new interconnectors adopt a more cautious approach to participation in the CM – all recent new interconnectors have only participated once they have taken FID and / or started construction. Based on this experience, we do not expect any of these new interconnectors to participate in the 2024/25 T-4 auction. It is possible that they may still be operational by 2024/25 and in theory, could participate in the 2024/25 T-1 auction instead.

On this basis, we therefore think it is reasonable that our modelled range does not include the de-rating factors from Leading the Way. This does not undermine the credibility of the scenario or mean that we consider it less likely. It merely reflects that we do not expect these interconnectors to participate in the 2024/25 T-4 auction. Should these projects decide to participate, then we would recommend that the de-rating factors be revised downwards to reflect the additional capacity when we undertake our Adjustment to the Demand Curve after prequalification. Should any of these projects decide to participate in the 2024/25 T-1 auction, then we will reassess de-rating factors at that point anyway, reflecting any interconnector capacity already secured.

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain on the assumption that this is more appropriately allowed for in the adjustments made to individual interconnector de-rating factors along with technical availability.

[70] This will affect interconnected markets even where no additional interconnector capacity is forecast above the levels in the other scenarios. For example, the Belgium de-rating factor will be affected if more interconnector capacity is available in France.

**Table 30: De-rating factor ranges by country**

| Country | Delivery Year | Minimum | Maximum |
|---|---|---|---|
| **Ireland** | 2021/22 | 53% | 99% |
| | 2024/25 | 19% | 66% |
| **France** | 2024/25 | 45% | 91% |
| **Belgium** | 2024/25 | 39% | 88% |
| **Netherlands** | 2024/25 | 34% | 84% |
| **Germany** | 2024/25 | 54% | 83% |
| **Denmark** | 2024/25 | 32% | 80% |
| **Norway** | 2024/25 | 91% | 100% |

**Table 31: De-rating factor ranges by country, excluding Leading the Way**

| Country | Delivery Year | Minimum | Maximum |
|---|---|---|---|
| **Ireland** | 2021/22 | 54% | 99% |
| | 2024/25 | 24% | 66% |
| **France** | 2024/25 | 50% | 91% |
| **Belgium** | 2024/25 | 46% | 88% |
| **Netherlands** | 2024/25 | 48% | 84% |
| **Germany** | 2024/25 | N/A | N/A |
| **Denmark** | 2024/25 | 45% | 80% |
| **Norway** | 2024/25 | 91% | 100% |

All interconnectors connected, or due to connect in any of the scenarios, already have Capacity Market contracts covering the T-1 2021/22 delivery year except for Moyle. Therefore, only Ireland is included in the 2021/22 de-rating factors.

# 5. Results and Recommendation for 2021/22 T-1 Auction

Our recommendation for the target capacity for the 2021/22 T-1 auction is 0 GW. This chapter presents the detailed modelling results to support our recommendation. Details to support our recommendation for the 2024/25 T-4 auction are described in Chapter 6. Further information on potential capacity requirements in the period out to 2034/35 can be found in Section 3.11.

## 5.1 Scenarios and Sensitivities to Model

The agreed scenarios and sensitivities to model for 2021/22 were as follows:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Steady Progression (SP)
- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): 6 sensitivities in 400 MW increments up to 2800 MW
- Over-Delivery (OVER DEL): 4 sensitivities in 400 MW increments up to 1600 MW

Further information on the scenarios and sensitivities can be found in Chapter 3.

## 5.2 Results

Table 32 below shows the modelling results sorted in order of de-rated capacity required to meet the Reliability Standard of 3 hours loss of load expectation (LOLE). It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and average cold spell (ACS) peak demand.

All cases modelled take account of Capacity Market units awarded contracts covering 2021/22 in the 2021/22 T-4 auction and units awarded multi-year contracts in the 2018/19, 2019/20 and 2020/21 T-4 auctions covering 2021/22 that are now known not to be able to honour their contracts – this known non-delivery totals 1.8 GW (de-rated).

Furthermore, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded multi-year contracts from the 2020/21 T-4 auction onwards has dropped by around 0.5 GW. In addition, for contracted transmission connected units, the scenarios and sensitivities (except high and low availability) assume a previously contracted capacity based on de-rated Transmission Entry Capacity (TEC) values and updated de-rating factors that are around 1.3 GW lower in aggregate than the contracted values in the CM register. These two changes have reduced the estimated previously contracted capacity for 2021/22 in the Base Case from the reported[71] figure of over 54.6 GW down to just over 52.8 GW.

No additional non-delivery is assumed in the Base Case and the FES scenarios with the exception of Steady Progression which assumes an additional 0.8 GW non-delivery in 2021/22.

## Table 32: Modelled de-rated capacities and peak demands – 2021/22

| | Name | Graph Code | Capacity to Secure (GW) | Outside CM (GW) | Previously Contracted Capacity (GW) | Over Or Non Delivery (GW) | Total derated capacity (GW) | ACS Peak (GW) |
|---|---|---|---|---|---|---|---|---|
| | Leading the Way | LW | -5.5 | 62.7 | 52.8 | 0.0 | 57.2 | 54.8 |
| | Warm Winter | BC_WARM | -4.6 | 62.7 | 52.8 | 0.0 | 58.0 | 57.8 |
| | Over Delivery Sensitivity: 1600 | BC_OVER_DEL_1600 | -3.9 | 64.9 | 52.8* | 1.6 | 61.0 | 57.8 |
| | High Availability | BC_HIGH_AVAIL | -3.9 | 64.1 | 54.2 | 0.0 | 60.2 | 57.8 |
| | Over Delivery Sensitivity: 1200 | BC_OVER_DEL_1200 | -3.5 | 64.5 | 52.8* | 1.2 | 61.0 | 57.8 |
| | Low Demand | BC_LOW_DEMAND | -3.4 | 62.9 | 52.8 | 0.0 | 59.5 | 56.6 |
| | Consumer Transformation | CT | -3.3 | 63.1 | 52.8 | 0.0 | 59.8 | 56.8 |
| | Over Delivery Sensitivity: 800 | BC_OVER_DEL_800 | -3.1 | 64.1 | 52.8* | 0.8 | 61.0 | 57.8 |
| | High Wind | BC_HIGH_WIND | -2.9 | 63.6 | 52.8 | 0.0 | 60.8 | 57.8 |
| | System Transformation | ST | -2.7 | 63.1 | 52.8 | 0.0 | 60.4 | 57.3 |
| | Over Delivery Sensitivity: 400 | BC_OVER_DEL_400 | -2.7 | 63.7 | 52.8* | 0.4 | 61.0 | 57.8 |
| | Base Case | BC | -2.3 | 63.3 | 52.8 | 0.0 | 61.0 | 57.8 |
| | Non Delivery Sensitivity: -400 | BC_NON_DEL_400 | -1.9 | 62.9 | 52.8* | -0.4 | 61.0 | 57.8 |
| | Cold Winter | BC_COLD | -1.7 | 63.5 | 52.8 | 0.0 | 61.8 | 57.8 |
| | Low Wind | BC_LOW_WIND | -1.6 | 62.8 | 52.8 | 0.0 | 61.2 | 57.8 |
| | Non Delivery Sensitivity: -800 | BC_NON_DEL_800 | -1.5 | 62.5 | 52.8* | -0.8 | 61.0 | 57.8 |
| | High Demand | BC_HIGH_DEMAND | -1.2 | 63.6 | 52.8 | 0.0 | 62.4 | 59.0 |
| | Non Delivery Sensitivity: -1200 | BC_NON_DEL_1200 | -1.1 | 62.1 | 52.8* | -1.2 | 61.0 | 57.8 |
| | Low Availability | BC_LOW_AVAIL | -0.8 | 62.4 | 51.5 | 0.0 | 61.7 | 57.8 |
| | Non Delivery Sensitivity: -1600 | BC_NON_DEL_1600 | -0.7 | 61.7 | 52.8* | -1.6 | 61.0 | 57.8 |
| | Non Delivery Sensitivity: -2000 | BC_NON_DEL_2000 | -0.3 | 61.3 | 52.8* | -2.0 | 61.0 | 57.8 |
| | Non Delivery Sensitivity: -2400 | BC_NON_DEL_2400 | 0.1 | 60.9 | 52.8* | -2.4 | 61.0 | 57.8 |
| | Non Delivery Sensitivity: -2800 | BC_NON_DEL_2800 | 0.5 | 60.5 | 52.8* | -2.8 | 61.0 | 57.8 |
| | Steady Progression | SP | 1.1 | 61.7 | 52.0 | 0.0 | 62.8 | 59.2 |

**Scenario Colour Key**
- Base Case
- Consumer Transformation
- System Transformation
- Leading the Way
- Steady Progression

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

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

*N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2021/22 that were awarded in previous auctions. This capacity is included in the 'Outside CM' capacity and is shown in a separate column. Note that the non-delivery & over-delivery sensitivities have been modelled by reducing and increasing the 'Outside CM' capacity respectively. The previously contracted figure does not take account of any changes to the interconnection EFC.*

The Leading the Way and Steady Progression scenarios define the extremes of the capacity to secure range for 2021/22 (-5.5 GW to 1.1 GW). In all cases except Steady Progression and the two highest non-delivery sensitivities, the capacity to secure is negative indicating that sufficient capacity has already been secured in previous actions to meet the 3 hours LOLE Reliability Standard.

[71] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202019%20DY2023%20Capacity%20Market%20Auction%20Final%20Results%20V1.0.pdf

## 5.3 Recommended Capacity to Secure

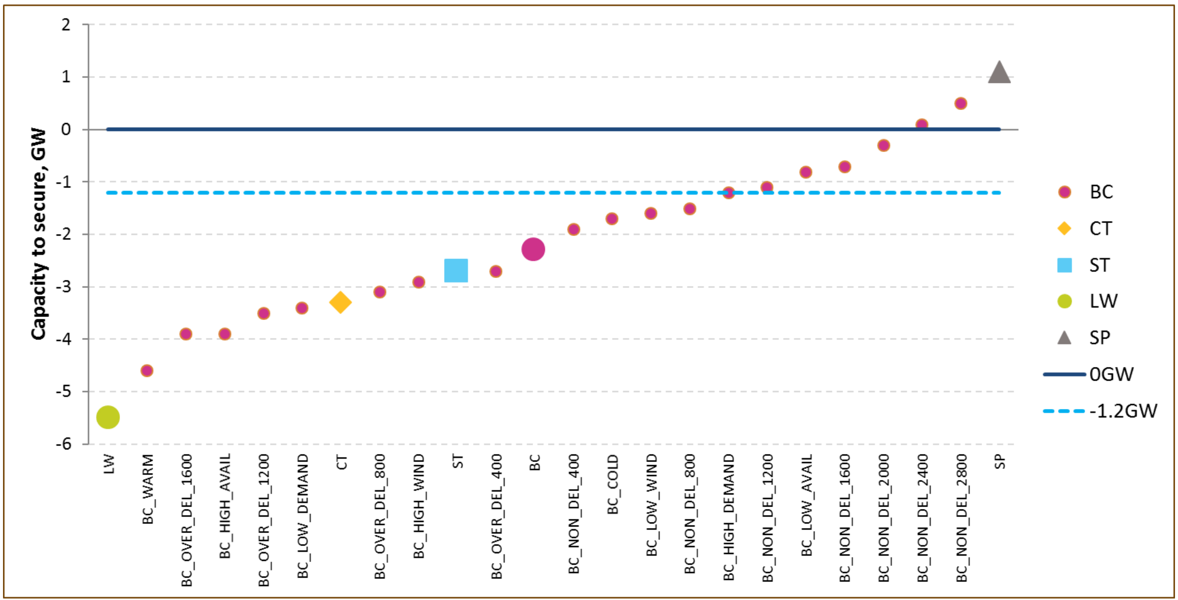
Table 32 above shows the capacity required to meet 3 hours LOLE in each of the cases modelled. However, if the capacity was selected based on one model run, but in 2021/22 the actual conditions matched a different model run, then capacity will have either been over or under secured, resulting in an LOLE lower or higher than 3 hours. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to secure value in 2021/22 taking account of the costs of under or over securing for all potential outcomes. If the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR).

Links to details on the LWR methodology are provided in the Annex A.7. As per previous ECR analysis, it uses a net CONE of £49/kW/year and an energy unserved cost of £17,000/MWh (consistent with the Government's Reliability Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the Least Worst Regret calculation applied to all of the scenarios and sensitivities is a capacity to secure for 2021/22 of -1.2 GW derived from the requirement of the nearest Base Case high demand sensitivity. This outcome excludes any capacity secured for 2021/22 in earlier T-4 auctions assumed in the Base Case. As per the conclusion of the T-1 LWR development project (see section 2.5.2 of the 2019 ECR), since the outcome of the LWR analysis is a negative capacity, we recommend a target of **0 GW**.

Figure 23 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR outcome (-1.2 GW) and recommendation (0 GW). Scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. The Steady Progression scenario has a positive requirement, higher than the other cases, mainly due to additional non-delivery assumed and a higher peak demand. Note that our recommendation concentrates on the target capacity alone.

**Figure 23: Least Worst Regret outcome and recommended capacity to secure compared to individual scenario / sensitivity runs – 2021/22**



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

### 5.3.1 Covered range

We consider that a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2021/22, then the LOLE 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 and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the above chart, securing a capacity of 0 GW (not running the auction) would result in 21 out of 24 cases being covered.

### 5.3.2 Adjustments to Target Capacity

Although we recommend that the T-1 auction target is 0 GW, the decision on whether to run an auction will be taken by the Secretary of State. If the auction is run, the final auction target will also be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the final T-1 auction target, a number of adjustments to the initial value (denoted by ***t*** GW) may need to be made (e.g. denoted by ***v***, ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Capacity with Long Term STOR contracts. (In previous auctions, long term STOR units that chose not to surrender their contracts were excluded from the CM and an adjustment made. Proposed changes could mean that these providers are now also eligible for CM agreements, which would mean such adjustments are no longer required in future) – ***v*** GW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine DSR to opt out but remain operational – ***x*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – ***y*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to contracted plants with different closure assumptions to the Base Case – ***z*** GW.*

Therefore, if the auction is run, the final auction target in the 2021/22 T-1 auction could be:

- ***t*** - ***v*** - ***x*** - ***y*** - ***z*** GW.

*National Grid ESO's modelling assumes no eligible 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.

### 5.3.3 Comparison with 2021/22 T-4 recommendation

In our 2017 Electricity Capacity Report, we recommended a capacity to secure for 2021/22 of 50.5 GW derived from the 2GW non-delivery sensitivity. Of this, the Secretary of State held back 0.4 GW for the 2021/22 T-1 auction leaving an initial target capacity of 50.1 GW for the T-4 auction. Following pre-qualification, the 2021/22 T-4 target was reduced by the Secretary of State to 49.5 GW with no changes to the 0.4 GW originally set aside for the 2021/22 T-1 auction. The 0.6 GW (net) of adjustments made to the 2021/22 T-4 target comprised of:

- A 0.65 GW reduction due to an increase in de-rated renewable capacity outside of the CM following the receipt of new information.
- Following a revision to embedded storage capacity, the Base Case Average Cold Spell (ACS) peak demand in 2021/22 was reduced to reflect the change in demand met by embedded storage capacity at peak leading to a 0.3 GW reduction
- A 0.1 GW reduction relating to long-term STOR outside of the CM.
- A 0.05 GW increase due to autogeneration assumed to be outside of the CM participating in prequalification
- Following the conclusion of a BEIS consultation on improving the Capacity Market framework, the de-rating factors for duration limited storage technologies were revised which reduced the previously contracted duration limited storage capacity. This led to a 0.4 GW increase in the T-4 target.

In general, when compared to the analysis for 2021/22 in the 2017 ECR that ultimately led to the 0.4 GW set aside by the Secretary of State for the T-1 auction, the 2020 ECR LWR outcome for 2021/22 is 1.6 GW lower than the 0.4 GW set aside. This difference is the result of the following increases and decreases.

The increases total 5.6 GW:

- 0.6 GW net increase relating to the demand curve adjustments made in 2017 following prequalification for the T-4 auction (see above for more details). These adjustments are no longer relevant for the T-1 auction as the prequalification for the T-1 auction has not yet taken place and the 2020 Base Case generation assumptions are different to the 2017 Base Case assumptions.
- Non-delivery since the 2017 Base Case, totalling 0.2 GW in 2021/22 (this is part of the 1.8 GW total known non-delivery - see Section 5.2).
- The contracted conventional capacity from previous T-4 auctions being 1.3 GW greater than the de-rated TEC (see Section 5.2).
- A 0.5 GW increase due to revised de-rating factors for duration-limited storage contracted resulting in a reduction of the de-rated capacity of such capacity awarded multi-year contracts from the 2020/21 T-4 auction onwards.

- A 2 GW increase due to the interconnection EFC calculated by the DDM (from the flow distribution described in Section 2.4.2) being lower than the interconnection capacity awarded agreements in the 2021/22 T-4 auction[72].
- A 0.5 GW increase in reserve for largest infeed loss compared to the 2019 Base Case.
- A 0.5 GW increase relating to lower levels of assumed opted-out or ineligible (below 1 MW) autogeneration[73] than the 2017 Base Case.

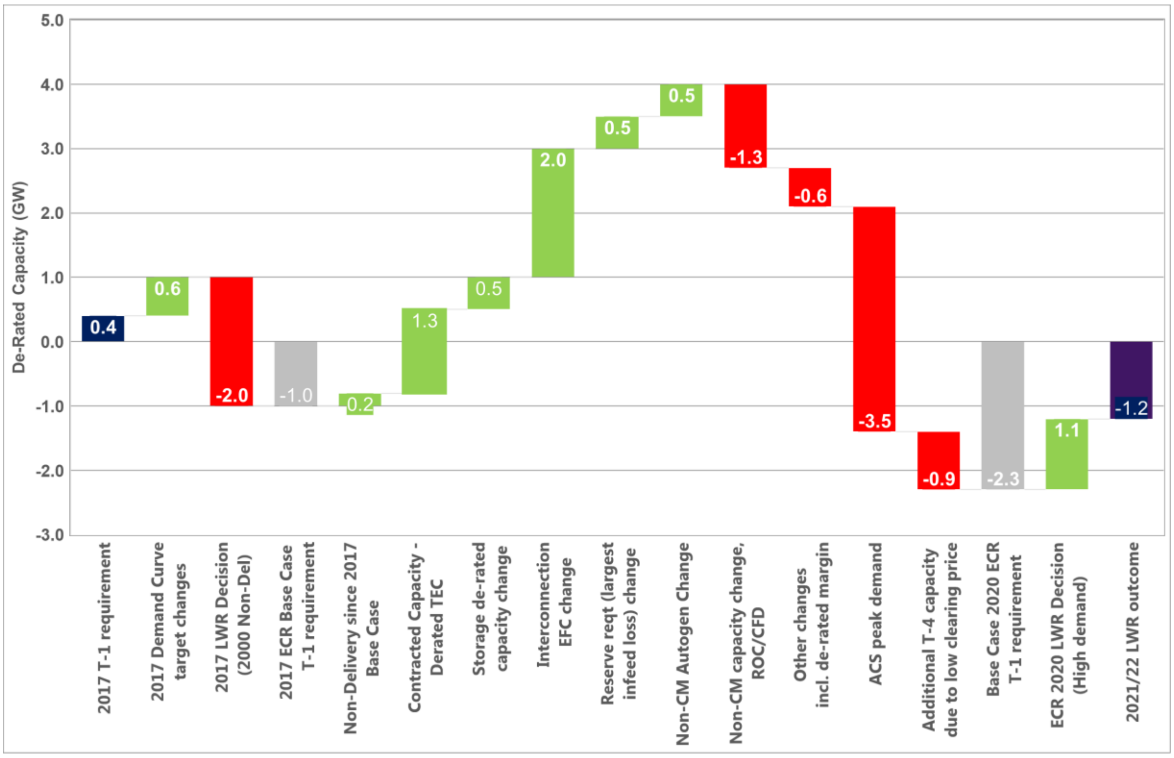
The decreases total 7.2 GW:

- A change in the scenarios and sensitivities modelled resulting in the LWR outcome difference from the Base Case being 0.9 GW lower (1.1 GW for high demand compared to 2 GW non-delivery).
- A 1.3 GW reduction resulting from higher non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely comprised of increased biomass, hydro and other small scale capacity offset by lower contributions at peak from landfill gas.
- A 0.6 GW net reduction due to other changes (change in de-rated margin required for 3 hours LOLE compared to the 2017 Base Case and rounding).
- A 3.5 GW reduction due to a lower peak demand in 2021/22 compared to the 2017 Base Case (see section on peak demand changes below).
- A reduction in requirement from over-securing in the 2021/22 T-4 auction by 0.9 GW due to a low clearing price.

The following waterfall chart, Figure 24, shows how the original 0.4 GW set aside for the 2021/22 T-1 auction (derived from the 2017 2000 MW non-delivery sensitivity) has changed into a LWR outcome of -1.2 GW (derived from the 2019 Base Case High Demand sensitivity) as a result of the 1.6 GW net decrease described above.

[72] The interconnection EFC calculated by DDM is lower than the previously contracted capacity but has no material impact on our recommendation of 0 GW (see Section 2.4.2.)
[73] Note that unsupported capacity under 1 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 1 MW under BEIS proposals https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

**Figure 24: Comparison with original 2021/22 T-1 requirement (de-rated)**

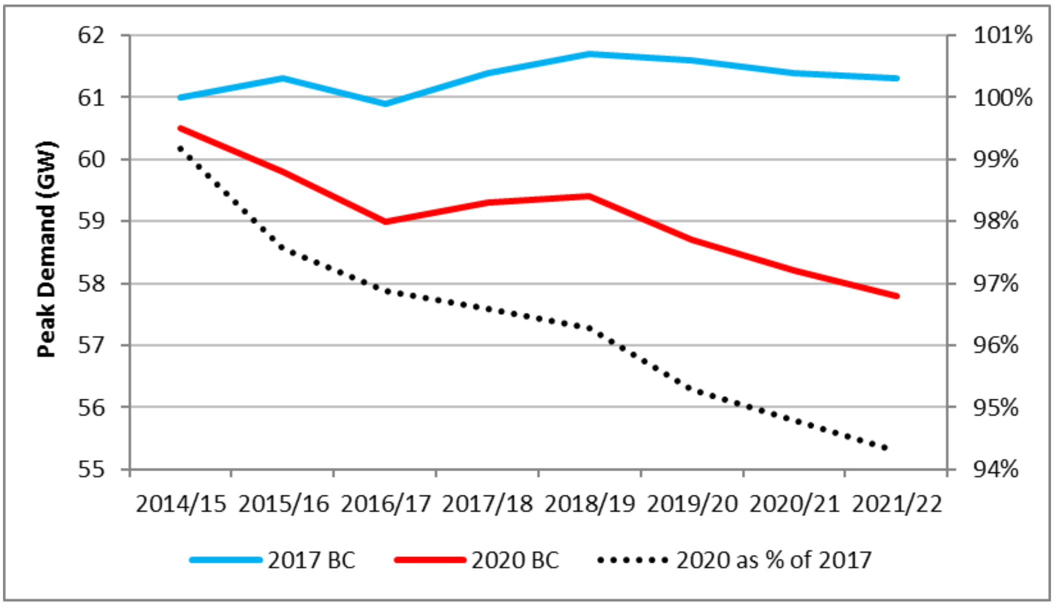



*Note: intermediate totals in grey above show requirements for 2017 Base Case and 2020 Base Case*

As highlighted above, since the 2017 ECR, the peak demand for 2021/22 has reduced by 3.5 GW (or 3.2 GW compared to the peak demand used in the final T-4 auction target – see start of Section 5.3.3 for more details).

Figure 25 compares the underlying ACS peak demand in the 2020 Base Case (2020 BC) to the underlying ACS peak demand in the 2017 Base Case (2017 BC) scenario over the period from 2014/15 to 2021/22.

**Figure 25: Peak Demand Comparison (2020 ECR v 2017 ECR)**



The following section compares the 2020 Base Case (2020 BC) against the 2017 Base Case (2017 BC) over the period 2014/15 to 2021/22. As has been noted before, the 2020 BC was finalised before the COVID-19 pandemic triggered global lockdowns, so this narrative does not take this event into account at this time.

There have been a number of improvements made to the data available to us since 2017.

- The most significant has been access to Electralink information, which allowed us to base our non-transmission generation assessment against first-hand, granular and comprehensive behaviour at peak times.
    - Previously our non-transmission generation dataset had been based on assessments of annualised average data, generation capacity lists from multiple sources, and modelling based on observed transmission data.
    - In order to correct our forecasting methods and improve future assessments, we recalculated historical demand against Electralink.
- Since 2017 we have improved the method for calculating historic restricted national demand and peak wind, which also resulted in smaller changes to historic demand.
- And between 2017 and 2020 we have updated our year ahead forecast against actual out-turn.
- In 2018, we obtained a monthly and anonymised dataset from Electralink. To a growing degree over time, this dataset has been used in Base Case assessment since then. As a large and relatively new dataset, we continue to analyse, assess and learn from it. As more robust trends and behaviours emerge we are integrating it into our forecasting processes as appropriate.

In 2017, it was thought that demand would remain relatively flat over the period, whereas we are now forecasting a decline in demand. The drivers for this are as follows:

- Historically since 2017, forecast economic activity has been consistently less than forecast, causing a reduction in peak electricity demand every year.
- In 2017 EU halogen legislation had been delayed, potentially indefinitely, driving a flattening of the Base Case. By 2019, EU halogen legislation has been reinstated so the anticipated impact has returned to our Base Case. The halogen legislation did remain in our overall range of scenarios but the Base Case took the best view at the time.
- Energy efficiency measures have also increased beyond what we assumed in our 2017 forecast.

This highlights the need to continue to monitor events, develop our methodologies and data sources, to enhance our understanding of peak demand and forecasting processes.

The letter written to Ofgem under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[74] and the steps taken to taken to improve the peak demand forecast.

[74] To be published at the same time as the ECR at https://www.emrdeliverybody.com/cm/home.aspx
The letter published in 2019 is available at
https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Demand%20Incentive%20Letter%202019.pdf

### 5.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities, a question was raised around how sensitive the LWR outcome was to the sensitivities included e.g. maximum level of non-delivery. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 33 below.

**Table 33: Sensitivity of LWR outcome (-1.2 GW) to LWR range**

| Sensitivities Added (+) or Removed (-) | -LW | -LW -Warm | - LW -Warm +2.0 GW OD | -SP | -SP -2.8 GW ND | +3.2 GW ND |
|---|---|---|---|---|---|---|
| 2021/22 outcome | -0.8 | -0.8 | -0.8 | -1.5 | -1.9 | -1.2 |

Removing the lowest case (LW) increased the outcome by 0.4 GW to -0.8 GW. Removing the next lowest case (warm winter) also resulted in an outcome of -0.8 GW. Adding an additional over-delivery case (2.0 GW) to this kept the outcome at 0.8 GW. Removing the highest case (SP) reduced the LWR tool outcome by 0.3 GW to -1.5 GW. Removing next highest case (the 2.8 GW ND case) as well resulted in a further reduction to the outcome of 0.8 GW to -1.9 GW. Increasing the maximum non-delivery to 3.2 GW did not change the original outcome (-1.2 GW).

Hence the outcome remains stable when removing either the lowest or highest sensitivity or adding additional OD and ND sensitivities – the outcome is only changed if one of the scenarios at either end of the range is removed.

Although the LWR outcome is stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.8 GW to address the risk associated with large thermal and nuclear plants, distributed generation, unproven DSR and interconnection.

To set this in context, for the 2024/25 T-4 auction around 1.8 GW of non-delivery has already been observed including 1.7 GW awarded multi-year agreements in the 2018/19 T-4 auction[75] that no longer has multi-year agreements.

However, given that the LWR outcome is negative in all selections examined, our recommendation (of 0 GW) is unaffected by the choice of highest and lowest cases.

[75] Note that the CM rules and penalty regime have changed since the 2018/19 T-4 auction

# 6. Results and Recommendation for 2024/25 T-4 Auction

Our recommendation for the target capacity for the 2024/25 T-4 auction is 41.6 GW. This chapter presents the detailed modelling results to support our recommendation. Results for 2021/22 can be found in Chapter 5. Further information on capacity requirements in years out to 2034/35 can be found in Section 3.11.

## 6.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2020 ECR. The agreed scenarios and sensitivities (covering non-delivery, over-delivery, weather, wind and demand) to model for 2024/25 are as follows:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Steady Progression (SP)
- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): 6 sensitivities in 400 MW increments up to 2400 MW
- Over-Delivery (OVER DEL): 4 sensitivities in 400 MW increments up to 1600 MW

## 6.2 Results

Table 34 shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All the scenarios and sensitivities modelled take account of Capacity Market units awarded multi-year capacity agreements covering 2024/25 in previous T-4 auctions that have had their contracts terminated – totalling 1.8 GW (de-rated). Furthermore, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded multi-year contracts from the 2020/21 T-4 auction onwards has dropped by around 0.5 GW. This change has reduced the estimated previously contracted capacity for 2024/25 from the reported[76] figure of approaching 6.8 GW down to just under 6.3 GW. No additional non-delivery is assumed in the Base Case. For the other scenarios between 0.1 GW and 0.2 GW of additional non-delivery is assumed in 2024/25.

**Table 34: Modelled de-rated capacities and peak demands - 2024/25**

| Name | Graph Code | Capacity to Secure (GW) | Outside CM (GW) | Previously Contracted Capacity (GW) | Over Or Non Delivery (GW) | Total derated capacity (GW) | ACS Peak (GW) |
|---|---|---|---|---|---|---|---|
| Leading the Way | LW | 37.4 | 20.6 | 6.1 | 0.0 | 58.0 | 54.3 |
| Warm Winter | BC_WARM | 38.5 | 19.9 | 6.3 | 0.0 | 58.4 | 57.5 |
| Over Delivery Sensitivity: 1600 | BC_OVER_DEL_1600 | 39.2 | 21.6 | 6.3* | 1.6 | 60.8 | 57.5 |
| Over Delivery Sensitivity: 1200 | BC_OVER_DEL_1200 | 39.6 | 21.2 | 6.3* | 1.2 | 60.8 | 57.5 |
| Low Demand | BC_LOW_DEMAND | 39.7 | 20.0 | 6.3 | 0.0 | 59.7 | 56.4 |
| System Transformation | ST | 39.8 | 19.8 | 6.2 | 0.0 | 59.6 | 56.3 |
| Over Delivery Sensitivity: 800 | BC_OVER_DEL_800 | 40.0 | 20.8 | 6.3* | 0.8 | 60.8 | 57.5 |
| High Wind | BC_HIGH_WIND | 40.3 | 20.5 | 6.3 | 0.0 | 60.8 | 57.5 |
| Over Delivery Sensitivity: 400 | BC_OVER_DEL_400 | 40.4 | 20.4 | 6.3* | 0.4 | 60.8 | 57.5 |
| Base Case | BC | 40.8 | 20.0 | 6.3 | 0.0 | 60.8 | 57.5 |
| Non Delivery Sensitivity: -400 | BC_NON_DEL_400 | 41.2 | 19.6 | 6.3* | -0.4 | 60.8 | 57.5 |
| Cold Winter | BC_COLD | 41.4 | 20.1 | 6.3 | 0.0 | 61.4 | 57.5 |
| Low Wind | BC_LOW_WIND | 41.5 | 19.3 | 6.3 | 0.0 | 60.8 | 57.5 |
| Non Delivery Sensitivity: -800 | BC_NON_DEL_800 | 41.6 | 19.2 | 6.3* | -0.8 | 60.8 | 57.5 |
| Consumer Transformation | CT | 41.7 | 20.0 | 6.2 | 0.0 | 61.7 | 57.8 |
| High Demand | BC_HIGH_DEMAND | 41.9 | 20.0 | 6.3 | 0.0 | 61.9 | 58.7 |
| Non Delivery Sensitivity: -1200 | BC_NON_DEL_1200 | 42.0 | 18.8 | 6.3* | -1.2 | 60.8 | 57.5 |
| Non Delivery Sensitivity: -1600 | BC_NON_DEL_1600 | 42.4 | 18.4 | 6.3* | -1.6 | 60.8 | 57.5 |
| Non Delivery Sensitivity: -2000 | BC_NON_DEL_2000 | 42.8 | 18.0 | 6.3* | -2.0 | 60.8 | 57.5 |
| Non Delivery Sensitivity: -2400 | BC_NON_DEL_2400 | 43.2 | 17.6 | 6.3* | -2.4 | 60.8 | 57.5 |
| Steady Progression | SP | 44.1 | 19.6 | 6.2 | 0.0 | 63.6 | 60.4 |

**Scenario Colour Key**
- Base Case
- Consumer Transformation
- System Transformation
- Leading the Way
- Steady Progression

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

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

*N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with multi-year contracts secured for 2024/25 in the 2018/19, 2019/20, 2020/21, 2021/22 and 2023/24 T-4 and 2022/23 T-3 auctions – this capacity is included in the 'Outside CM' capacity and is also shown in a separate column. Note that the non-delivery and over-delivery sensitivities have been modelled by reducing and increasing the 'Outside CM' capacity respectively.*

The Leading the Way and Steady Progression scenarios define the extremes of the capacity to secure range for 2024/25 (37.4 GW to 44.1 GW).

## 6.3 Recommended Capacity to Secure

Table 34 shows the de-rated capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2024/25, the actual conditions matched a different model run, then capacity will have either been over or under secured, resulting in an LOLE lower or higher than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to secure in 2024/25, taking account of the costs of under or over securing for all potential outcomes. If the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR).

Links to details on the LWR methodology are provided in the Annex A.7. As per previous ECR analysis, it uses a net Cost of New Entry (CONE) of £49/kW/year and an energy

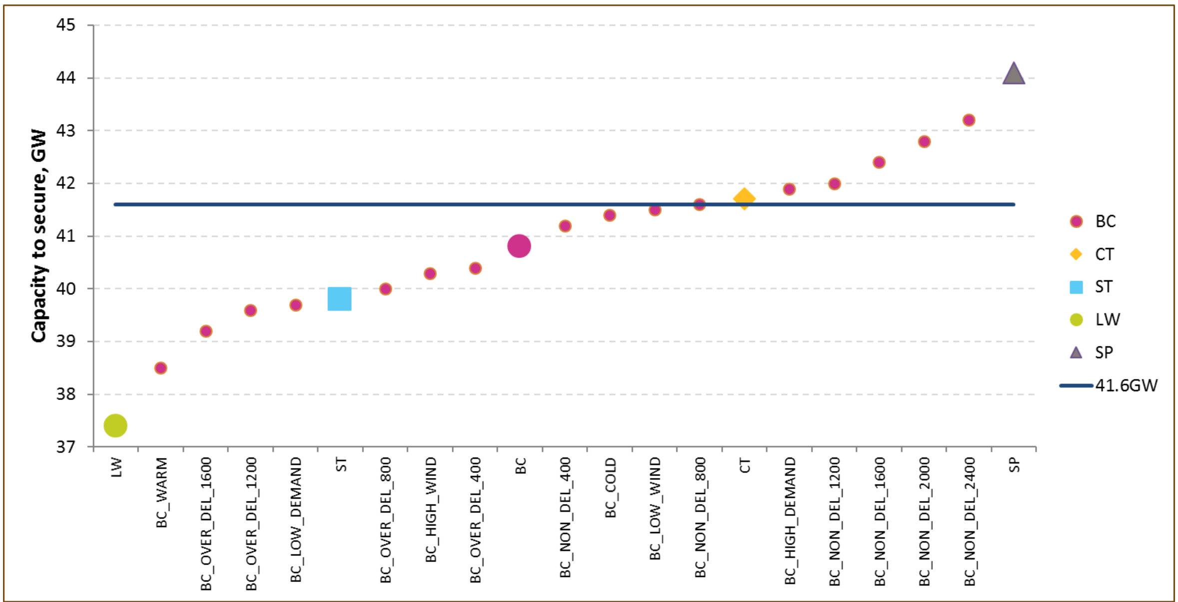
[76] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202019%20DY2023%20Capacity%20Market%20Auction%20Final%20Results%20V1.0.pdf

unserved cost of £17,000/MWh (consistent with the Government's Reliability Standard) to select a scenario / sensitivity from which the recommended capacity to secure is derived.

The outcome of the Least Worst Regret calculation applied to all of National Grid ESO's scenarios and sensitivities is a capacity to secure for 2024/25 of **41.6 GW** derived from the requirement of the nearest Base Case sensitivity (800 MW non-delivery) to the Consumer Transformation requirement (41.7 GW) selected by the LWR tool. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2024/25 in earlier T-4 auctions that is assumed in the Base Case.

Figure 26 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR recommendation. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note that our recommendation concentrates on the target capacity alone.

**Figure 26: Least Worst Regret recommended capacity to secure compared to individual scenario / sensitivity runs – 2024/25**




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

## 6.3.1 Covered range

We consider that 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 2024/25, 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 and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the chart, securing a capacity of 41.6 GW would result in 14 out of 21 cases 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 pre-qualification. To obtain the capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by ***v***, ***w***, ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Capacity with Long Term STOR contracts. (In previous auctions, long term STOR units that chose not to surrender their contracts were excluded from the CM and an adjustment made. Proposed changes could mean that these providers are now also eligible for CM agreements, which would mean such adjustments are no longer required in future) – ***v*** GW.
- Government (upon confirming auction parameters to National Grid ESO prior to auction guidelines) will determine how much capacity to hold back for the 2024/25 T-1 auction – ***w*** GW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine DSR to opt-out but remain operational – ***x*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – ***y*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will 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 – ***z*** GW.*

Therefore, the recommended capacity to secure through the 2024/25 T-4 auction could be:

- 41.6 GW - ***v*** - ***w*** - ***x*** - ***y*** - ***z***.

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

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

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours, the demand curve for the auction will result in a capacity from a range around the target capacity. Thus, a recommended de-rated capacity of 41.6 GW could result in a differing capacity volume depending on the clearing price set by the marginal unit. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any differences between the cleared capacity and the target capacity in the T-4 auction can be accounted for in the T-1 auction.

### 6.3.3 Comparison with 2023/24 T-4 recommendation

In our 2019 Electricity Capacity Report, we recommended a capacity to secure for 2023/24 of 44.7 GW, 0.7 GW above our Base Case requirement of 44.0 GW which assumed over 4.5 GW of previously contracted capacity (net of 0.4 GW storage de-rating factor change).

In general, when compared to the analysis for 2023/24 in the 2019 ECR, the 2020 ECR recommendation for 2024/25 is 3.1 GW lower. This difference is the result of the following increases and decreases.

The increases total 0.5 GW:

- A 0.2 GW increase resulting from lower assumed opted-out or ineligible (below 1 MW) autogeneration.[77]
- An increase of 0.1 GW due to a small change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards (0.5 GW reduction in the 2020 ECR compared to a 0.4 GW reduction in the 2019 ECR).
- A 0.1 GW increase in reserve for largest infeed loss compared to the 2019 Base Case.
- A small increase of 0.1 GW resulting from a slightly increased differential of the LWR outcome to the Base Case - the cold winter sensitivity with a differential of 700 MW set the LWR requirement in the 2019 ECR and the 800 MW non-delivery sensitivity in the 2020 ECR.

The decreases total 3.6 GW:

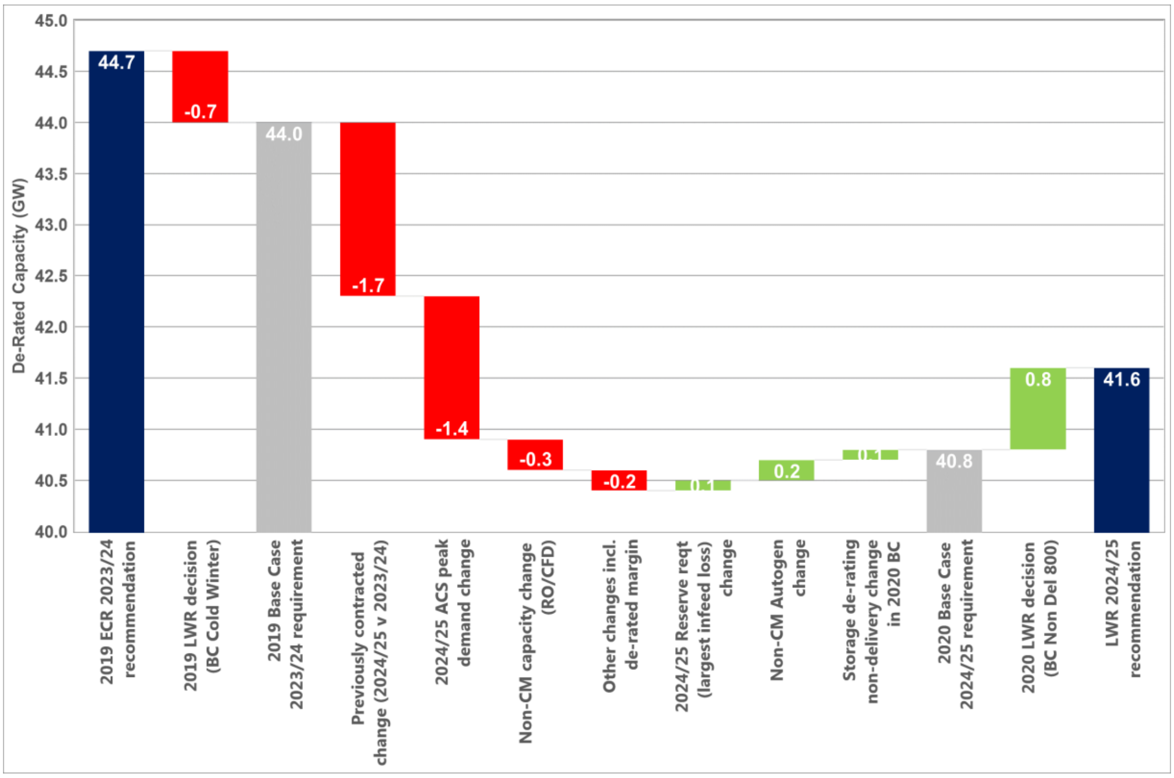
- A 1.7 GW reduction due to an increase in previously contracted capacity arising from capacity awarded multi-year agreements in the 2022/23 T-3 and 2023/24 T-4 auctions.
- A 1.4 GW reduction due to a lower peak demand for 2024/25 compared to the 2019 Base Case peak demand for 2023/24 (due to reduced residential demand as a result of the halogen lighting ban, reduced industrial demand, a reduced 2018/19 outturn peak demand, partly offset by increased EV sales and heat pump demand – see Section 3.3 for more details).
- A 0.3 GW decrease resulting from higher non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely the result of a higher wind EFC.
- A 0.2 GW decrease due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2019 Base Case and rounding).

This analysis includes the risk of further non-delivery (up to a maximum of 2.4 GW in the most extreme non-delivery sensitivity). However, we note that if this non-delivery risk were to reduce, this could result in a lower demand curve target in the T-1 auction, which will be reassessed in the 2023 ECR.

[77] Note that unsupported capacity under 1 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 1 MW under BEIS proposals – see https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

The following waterfall chart, Figure 27, shows how the original 44.7 GW requirement for the 2023/24 T-4 auction (derived from the 2019 Base Case cold winter sensitivity) has changed into a recommended requirement of 41.6 GW (derived from the 2020 Base Case 800 MW non-delivery sensitivity) as a result of the 3.1 GW net reduction described above.

**Figure 27: Comparison with recommended 2023/24 T-4 requirement in 2019 ECR**




*Note: intermediate totals in grey above show requirements for 2019 Base Case and 2020 Base Case*

Section 3.11 shows how the requirement for CM-eligible capacity changes over a 15-year horizon. This section shows a general increase for two of the scenarios modelled as a result of higher peak demands. For the other two scenarios, the requirement remains generally stable across most of the period, as increases in peak demand are offset by increases in non-CM capacity. For one scenario, there is a decline in the last few years resulting from an increase in low carbon capacity outside of the CM such as new nuclear. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. During the later years of the period, significant amounts of RO-supported wind capacity will also come off support reducing the capacity outside of the CM and increasing the requirement for the CM-eligible capacity.

## 6.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities, a question was raised around how sensitive the LWR outcome was to the sensitivities included e.g. maximum level of non-delivery. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 35.

**Table 35: Sensitivity of LWR outcome (41.6 GW) to LWR range**

| Sensitivities Added (+) or Removed (-) | -LW | -LW - Warm | -LW - Warm +2.0 OD | -SP | -SP -2.4 ND | +2.8 ND |
|---|---|---|---|---|---|---|
| 2024/25 outcome (GW) | 42.0 | 42.4 | 42.0 | 41.2 | 40.8 | 41.6 |

Removing the lowest case (LW) increased the outcome by 0.4 GW to 42.0 GW. Removing the next lowest case (warm winter) as well increased the outcome to 42.4 GW. Adding an additional over-delivery case (2.0 GW) to this brought the outcome back down to 42.0 GW. Removing the highest case (SP) reduced the LWR tool outcome by 0.4 GW to 41.2 GW. Removing next highest case (the 2.4 GW ND case) as well resulted in a further reduction to the outcome of 0.4 GW to 40.8 GW. Increasing the maximum non-delivery to 2.8 GW did not change the original outcome (41.6 GW).

Hence the outcome remains stable when removing either the lowest or highest sensitivity or adding additional OD and ND sensitivities – the outcome is only changed if one of the scenarios at either end of the range is removed.

Although the LWR outcome is stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.4 GW to address the risk associated with large thermal and nuclear plants, distributed generation, unproven DSR and interconnection.

To set this in context, for the 2024/25 T-4 auction around 1.8 GW of non-delivery has already been observed including 1.7 GW awarded multi-year agreements in the 2018/19 T-4 auction[78] that no longer has multi-year agreements.

[78] Note that the CM rules and penalty regime have changed since the 2018/19 T-4 auction

# A. Annex

## A.1 Demand Methodology

The demand projections are developed using in-house analysis which has used stakeholder feedback to inform it. Annual demands can be considered with the following breakdown:

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

### Domestic

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

- **Appliances, including lighting:** A regression trend method flexed by the application of primary assumptions and appliance number caps. We have assumed energy efficiency gains in all our scenarios but with varying degrees depending on the scenario.
- **Resistive heat and hot water:** A methodology has been applied where we use the thermal efficiency of the housing stock rather than just the insulation to inform our modelling. The scenarios have been revised based on recent information. In decarbonising scenarios, the average household thermal efficiency will be much improved on today's average. Current electrical heat demand comes from published statistics[79].
- **Heat pumps:** All scenarios are a patchwork of heating technologies due to regional variations and the expectation that no single technology will dominate low carbon heat. As well as heat pumps: hydrogen, biomass, natural gas are also considered in scenario design. Heat pumps are assumed to be one of the key heat decarbonisation technologies and this has been reflected in the scenarios for many years. In the residential sector, air source heat pumps (ASHP) and hybrid air source heat pumps are rolled out to different degrees. Ground Source Heat Pump (GSHP) installations are fewer due to high installation cost and payback periods. District heat is largely powered by larger heat pumps, which in addition have access to a top up source of heat (e.g. gas/hydrogen/biomass boiler, and/or thermal storage). In decarbonising worlds, heat pumps are also assumed to penetrate into industrial "warm" processes and commercial space heat. Thermal storage in all sectors is assumed to be installed to differing degrees in order to optimise the overall GB energy system, particularly peak demands during winter.

[79] https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

- **Consumer Flexibility:** This year, similarly to last year, Ofgem's updated retail market review data has been used alongside research from recent studies, to forward project customer engagement rates. This percentage is applied to the underlying domestic demand and also plays a role in engagement in relation to transport demand.

## Industrial

Economic data provided by 'Oxford Economics' in Q4 of each year is used to create economic cases for GB economic growth. Retail energy price forecasts are also provided. A range of price scenarios was used to improve the illustration of future uncertainty.

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

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

Finally, calculations are added which consider the impact of energy efficiency policy within the different scenarios.

## Commercial

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

## Transport

- **Road transport:** A new model was adopted in 2018, based on economics and a Bass Diffusion approach to forecast uptake rates of different vehicles (i.e. natural gas and hydrogen as well as electric vehicles) that may replace the Internal Combustion Engine as transport is decarbonised. This is combined with statistics on journey length in order to assess the associated electrical demand. We continue to incorporate the concept of vehicle sharing, autonomous vehicles and vehicle to grid electricity supply. Stakeholder feedback on this approach continues to be positive.
- **Rail**: Projections are applied to the electric rail demand based on stakeholder feedback, to illustrate different levels of rail transport electrification.

## Other/Sundry

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

## Peak Demands

Once the assessment of underlying annual demand is created, a recent historical relationship of annual to peak demand is applied. This creates an underlying peak demand to which peak demand components that history cannot predict are added. For example, electric vehicle charging or heat pump demand at times of peak demands on the transmission system.

For each of the scenarios we also applied a consumer engagement factor which increases in our greener scenarios.

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. For 2019, new data from an innovation project (Development of GB Electric Vehicle Charging Trials)[80] was used to review and revise our modelling on home, workplace and public charging. Smart charging behaviour is assumed to differing degrees in all scenarios.
- **Heat pumps:** The number of heat pumps and heat demand, data from manufacturers, and trial within day profiles combined with performance statistics and historical weather trends are used to determine the electrical heat demand at peak. Thermal storage is assumed in the low carbon scenarios as part of the smart energy system and acts to reduce peak heat demands.
- **Losses:** As with annual demand, this is a function of total peak demand.
- **Industrial & Commercial Demand Side Response:** Created using desktop research and assumptions of future efficiency improvements, consumer engagement and information technology improvements.
- **Domestic peak response:** As with annual demand this starts with the smart meter roll-out numbers, project outcome data and perceived customer engagement rates. From this results a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

## Calibration

Both annual and peak demands are calibrated. Annual demands are calibrated to weather corrected metered transmission data, BEIS information and the FES assessment of non-transmission generation. Peak demand is calibrated with weather corrected metered transmission demand. Recently obtained Electralink and Elexon data is being used to enhance this method.

[80] http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/04/20190329-NG-EV-CHARGING-BEHAVIOUR-STUDY-FINAL-REPORT-V1-EXTERNAL.pdf

### Results

The results of the described methods provided are defined and shown in the Annex (Section A.4.1). For a more detailed description of the methodology and FES scenarios please refer to the FES document or its workbook[81]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

### Recent forecasting performance

The PTE included data on National Grid ESO's demand forecasting performance in their 2019 report. Table 36 provides an updated view of this data showing a comparison of National Grid ESO's winter ahead ACS restricted national demand forecast against outturn values. 2019/20 out-turn value is provisional and denoted by *.

**Table 36: ACS Restricted National Demand Forecasting Accuracy**

| Winter | FES Year | ACS Restricted National Demand Out-turn | SYS/FES Base View Restricted National Demand | Base View Error (%) | Base View Error (GW) |
|---|---|---|---|---|---|
| 2008/09 | | 57.4 | 59.3 | 3.3% | 1.9 |
| 2009/10 | | 57.2 | 55.5 | -3.0% | -1.7 |
| 2010/11 | SYS 2010 | 57.1 | 57.0 | -0.2% | -0.1 |
| 2011/12 | SYS 2011 | 55.4 | 57.5 | 3.8% | 2.1 |
| 2012/13 | FES 2012 | 54.7 | 55.4 | 1.3% | 0.7 |
| 2013/14 | FES 2013 | 53.7 | 55.3 | 3.0% | 1.6 |
| 2014/15 | FES 2014 | 53.0 | 53.3 | 0.6% | 0.3 |
| 2015/16 | FES 2015 | 51.1 | 53.2 | 4.1% | 2.1 |
| 2016/17 | FES 2016 | 50.3 | 51.1 | 1.6% | 0.8 |
| 2017/18 | FES 2017 | 49.4 | 50.1 | 1.4% | 0.7 |
| 2018/19 | FES 2018 | 47.6 | 47.4 | -0.4% | -0.2 |
| 2019/20 | FES 2019 | 46.2* | 45.1 | -2.4%* | -1.1* |

## A.2 Generation Methodology

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

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

The placement of a power station was determined by a number of factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that particular power station, are also taken into account. The contracted background or Transmission Entry Capacity (TEC) Register[82] 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

[81] http://fes.nationalgrid.com/fes-document/
[82] https://www.nationalgrideso.com/connections/registers-reports-and-guidance

a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also taken into account.

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

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

### A.2.1 Contracted Background

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

### A.2.2 Market Intelligence

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

#### Developer Profile

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

1. 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?
2. 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:

1. At what stage of development or deployment is the technology, e.g. has the technology been proven as a viable source of electricity generation?
2. Have there been trial/pilot projects carried out as with technologies such as wave and tidal?
3. Has there been a commercial scale roll-out of the technology following successful trial/pilot schemes?

4. Is there Government backing and support for the new technology?
5. Are there any industry papers or research regarding the roll-out of new technologies in terms of the potential scale of deployment should the technology be proven?

**Financial Markets**

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

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

### A.2.3 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 results of the analysis inform the transmission generation backgrounds, particularly plant closure profiles.

### A.2.4 Project Status

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

### A.2.5 Government Policy and Legislation

It is important that the power supply scenarios reflect Government policy and initiatives for particular generation projects and / or technologies. 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 such as the Capacity Market that aims to ensure that there is sufficient capacity on the system to meet the Reliability Standard.

Energy legislation enacted at the European and national level will impact which power supply sources are developed and connected to the NETS. For example, renewable energy targets are intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, therefore making it very likely in FES scenarios with a high green ambition that the NETS will experience much more intermittent renewable capacity. Another example is the plant that may have to be modified to comply with environmental directives, such as the

Industrial Emissions Directive (IED) and the Medium Combustion Plant Directive (MCPD). This legislation places restrictions on the number of running hours for fossil fuel power generation plants with regard to the harmful waste gases that they emit, unless investments are made to reduce this impact, and will affect decisions on whether to invest in new plants or maintain existing facilities.

### A.2.6 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered. The 2020 power generation backgrounds are developed to both meet demand and to reflect the implementation of the GB Reliability Standard of 3 hours Loss of Load Expectation (LOLE) / year. In the early years of the FES study period, the generation backgrounds were driven by relatively more granular intelligence and therefore LOLE could potentially vary significantly year to year within this period. This can, for instance, be caused by plants without CM contracts staying open.

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

## A.3 EMR/Capacity Assessment Development Projects Matrix

Table 37 lists all the proposed development projects and their respective scores. Based on the process described in Section 2.5.1, only projects 1-14 attracted high enough scores to qualify for this year’s development phase.

Following the initial prioritisation, projects 7, 10 and 12 were deprioritised to give way to projects 16 and 29. Note that shaded projects either did not score high enough or were deprioritised and therefore were not progressed. Also, projects 37, 38 and 39 were already in progress before the prioritisation process began and hence were not scored.

**Table 37: Development Projects Matrix**

| Development Project Description | Total* |
|---|---|
| 1) Consider the most expedient way to motivate a comprehensive Distribution Network Operator (DNO) compiled register of embedded connection capacities. (PTE Recommendation 47) | 18.5 |
| 2) Undertake steps to explain and de-bias demand forecasts so that PTE recommended adjustments will not be necessary. (PTE Recommendation 43) | 17 |
| 3) Assessment of what an ageing and renewing fleet implies for the extrapolation of possible trends from historical availabilities (considers whether review of nuclear de-rating is required).(PTE Recommendation 45) | 16 |
| 4) Investigate and recommend approach to use for 2020 interconnected country de-rating factor analysis. | 15 |
| 5) Investigate and recommend the model (i.e. DDM version) to use for capacity to secure modelling in 2020 ECR. | 15 |
| 6) Register of embedded generators is established showing the status of connections and expected commissioning dates by plant. (PTE Recommendation 48) | 13 |

| Development Project Description | Total* |
|---|---|
| 7) Undertake a historical analysis to determine the extent to which stress events on the GB system have been due to the combined events and to assess whether such combinations might arise again. Deprioritised due to lack of data. (PTE Recommendation 39) | 12 |
| 8) Reconsider approach to include some Black Swan and Combined Sensitivities to reflect the changing market circumstances. (PTE Recommendation 46) | 11.5 |
| 9) Develop methodology for dealing with co-located facilities. Phase 1 of this project involved developing the Unserved Energy Model (UEM) to handle constrained co-located sites (PTE Recommendation 51). | 11 |
| 10) Once robust technology and capacity data for embedded generators can be obtained, develop an approach for calculating de-rating factors for conventional embedded generation technologies. Deprioritised as data was not available in time. | 10 |
| 11) Support ENTSO-E working group on security of supply. | 9 |
| 12) Investigate the evidence for selecting a wider sensitivity band for demand outturns for overall demand. Deprioritsed as it was addressed via a wider peak demand range across the scenarios. (PTE Recommendation 38). | 9 |
| 13) Support ENTSO-E working group on VoLL. | 8.5 |
| 14) Streamlining of process that translates FES data into the format required by the DDM. | 8 |
| 15) Support BEIS 5-year review of the Capacity Market and Reliability Standard. | 7.5 |
| 16) Streamline / automate the process to create LOLE and EFC proxies for the FES generation backgrounds to save time. | 7 |
| 17) Review offshore wind power curves and consider creating large offshore power curve if additional data is available for large offshore wind turbines. | 7 |
| 18) Consider duration-limits (if any) in the DSR and diesel generation technology types. | 7 |
| 19) Estimate the range of potential impact of non-delivery and over-delivery of non-CM (e.g. renewable) capacity in the Base Case. | 7 |
| 20) Provide a more explicit analysis of the potential load shape evolutions and their implications for peak demand.<br>(PTE Recommendation 44). | 7 |
| 21) Develop methodologies for calculating de-rating factors for new technologies that may enter the CM auctions (e.g. large scale transmission-connected EV charging stations involving storage, Vehicle to Grid (V2G) aggregations, voltage reduction as demonstrated via the CLASS project, etc.). | 7 |
| 22) Build upon previous economic modelling of the viability of embedded generators to provide a more comprehensive view on potential embedded non-delivery.<br>(PTE Recommendation 49) | 7 |
| 23) Review treatment of non-CM capacity in the DDM to better account for capacity in later years (after CM target years) that comes to the end of its CFD / RO contracts. | 6 |
| 24) Undertake a re-evaluation of the sensitivity of the LOLE and EEU calculations to the growth in smaller generators, also with regard to the technologies with possible duration-limited performance. (PTE Recommendation 42) | 6 |
| 25) Investigate the present version of CA model wind processing tool R code and assess its impact on the Capacity Assessment (CA) model wind processing tool. | 5.5 |
| 26) Update CA model translation tool to read Generation Background new format. | 5 |
| 27) Improve historical demand time series for LOLE modelling (using Electralink data). | 5 |
| 28) Develop a 'net demand' version of the CA and DDM models, to avoid the use of an exogenous scalar applied to wind storage and solar in the time collapsed calculations. | 5 |
| 29) BEIS project request on small power generation and emissions. | 4 |
| 30) Analyse the impact of scarcity pricing on peak demand and also examine demand responses to high prices in markets that have already begun to roll out active management tools. (PTE Recommendation 29) | 3.5 |
| 31) Investigate the economic drivers of the DSR sector and distributional impacts of Ofgem's proposed changes to the charging regime.<br>(PTE Recommendation 50). | 2.5 |
| 32) Undertake a pro-active role in informing the public about the issues in maintaining security of electricity supply, including the nature of risk and probability, and associated trade-offs. Co-ordinate through the Energy Networks Association (ENA) or code group with support from Energy UK and Association of Distributed Energy (ADE). (PTE Recommendation 30). | 2 |
| 33) Develop a demand time series shape for FES future security of supply modelling - at the moment 2005-2017 demand time series shapes are being used, but these are likely to be inadequate for > FES 2030 margins assessment work. | 2 |
| 34) Consider rationalising number of models e.g. by carrying out Winter Outlook analysis using BID3 instead of the CA model. This project could also consider any changes in the functionality required for the models used by the team (BID3 / DDM + UEM) e.g. move to net demand or sequential model. | 1.5 |
| 35) Consider the range of additional forms of 'latent capacity' (such as various possible responses of DNOs to demand reduction requests) in addition to previous work on collecting information on | -1 |

| Development Project Description | Total* |
|---|---|
| how DNOs plan to respond to Demand Control orders to ensure security of supply. (PTE Recommendation 35). | |
| 36) If the introduction of a large offshore wind power curve is justified, update models (CA model, DDM, UEM) to incorporate this new class. Calculate the impact on de-rating factors, LOLE, capacity to secure etc. | -2 |
| 37) In the last year target-setting process, PTE recommended a reduction of 800MW to the target recommendation, reasoning that they saw a consistent pattern of over-estimation in the demand forecasts. ESO to undertake analysis to review this and reach a common position on this 800MW issue. | Not Scored |
| 38) PTE to review their previous recommendations and reduce the number for projects they are leading.<br>(PTE Recommendation 41) | Not Scored |
| 39) In view of the issues in gathering data necessary for assessing national energy security requirements, BEIS, ESO and Ofgem should urgently consider whether and when an information strategy might be required. (PTE Recommendation 37) | Not Scored |

*represents total scores based on scorings provided by National Grid ESO, BEIS and Ofgem.

## A.4 Detailed Modelling Assumptions

The following sections describe in more detail the modelling assumptions outlined in the main report. National Grid ESO provides the details of the key inputs for the DDM model. Other assumptions (e.g. technology costs) were provided by BEIS.

### A.4.1 Demand (annual and peak)

Table 38 shows the annual demand while Table 39 shows the 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 the Base Case (except for the high and low demand sensitivities where the peak demand is 2% above / below the Base Case peak demand).

**Table 38: Annual Demand* by scenario**

| Annual Demand (TWh) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|
| Base Case | 307 | 306 | 305 | 303 | 302 | 301 | 295 | 296 |
| Consumer Transformation | 307 | 302 | 297 | 295 | 296 | 298 | 300 | 304 |
| System Transformation | 307 | 304 | 300 | 298 | 296 | 295 | 295 | 296 |
| Leading the Way | 301 | 291 | 285 | 281 | 279 | 278 | 279 | 281 |
| Steady Progression | 310 | 312 | 313 | 315 | 316 | 318 | 319 | 319 |

| Annual Demand (TWh) | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|
| Base Case | 297 | 298 | 301 | 304 | 309 | 316 | 323 | 331 |
| Consumer Transformation | 308 | 313 | 318 | 326 | 336 | 347 | 359 | 370 |
| System Transformation | 297 | 298 | 301 | 304 | 309 | 316 | 323 | 331 |
| Leading the Way | 285 | 290 | 295 | 304 | 313 | 324 | 335 | 344 |
| Steady Progression | 320 | 322 | 323 | 327 | 330 | 335 | 340 | 345 |

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

**Table 39: Peak Demand* by scenario**

| Peak Demand (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| Base Case | 58.2 | 57.8 | 57.6 | 57.5 | 57.5 | 56.4 | 56.8 | 57.4 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Consumer Transformation | 58.1 | 56.8 | 56.0 | 56.8 | 57.8 | 58.9 | 60.0 | 61.9 |
| System Transformation | 58.1 | 57.3 | 56.6 | 56.4 | 56.3 | 56.4 | 56.8 | 57.4 |
| Leading the Way | 56.5 | 54.8 | 54.1 | 54.0 | 54.3 | 54.8 | 55.4 | 57.0 |
| Steady Progression | 58.8 | 59.2 | 59.5 | 60.0 | 60.4 | 60.8 | 60.8 | 61.1 |

| Peak Demand (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| Base Case | 58.0 | 58.7 | 59.1 | 60.0 | 60.9 | 62.2 | 63.5 |
| Consumer Transformation | 63.6 | 65.2 | 66.5 | 68.3 | 69.9 | 72.4 | 74.3 |
| System Transformation | 58.0 | 58.7 | 59.1 | 60.0 | 60.9 | 62.2 | 63.5 |
| Leading the Way | 58.5 | 59.6 | 60.7 | 62.2 | 63.4 | 64.4 | 65.2 |
| Steady Progression | 61.4 | 61.8 | 62.1 | 63.0 | 63.8 | 64.7 | 65.6 |

*The definition of peak demand is unrestricted[83] GB National Demand plus demand supplied by distributed generation.

## A.4.2 Generation Capacity Mix

Tables 40 to 44 show the generation mix (nameplate capacity at winter peak, excluding solar PV) for the 4 FES scenarios and Base Case from the DDM model. The Non-CM capacity shows increases in most years after 2020/21 but falls in some years where large amounts of wind come off RO support and increases more slowly in 2027/28 due to the end of RO and CFD support for biomass conversion.

**Table 40: Base Case generation capacity mix**

| Capacity (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| CM eligible | 67.6 | 65.9 | 64.2 | 63.7 | 59.7 | 59.7 | 63.0 | 68.4 |
| Non-CM | 31.7 | 34.9 | 36.0 | 36.5 | 40.4 | 46.2 | 49.6 | 52.6 |
| Total peak capacity | 99.3 | 100.8 | 100.3 | 100.1 | 100.1 | 105.9 | 112.6 | 120.9 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| CM eligible | 69.3 | 71.9 | 73.9 | 75.0 | 76.7 | 77.3 | 75.8 |
| Non-CM | 53.9 | 57.7 | 56.3 | 65.2 | 66.8 | 77.5 | 80.6 |
| Total peak capacity | 123.2 | 129.5 | 130.2 | 140.2 | 143.5 | 154.8 | 156.4 |

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

### Table 41: Consumer Transformation generation capacity mix

| Capacity (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| CM eligible | 67.7 | 67.1 | 68.4 | 67.7 | 61.6 | 67.1 | 68.7 | 75.1 |
| Non-CM | 31.6 | 34.9 | 35.6 | 36.9 | 40.3 | 46.5 | 52.3 | 54.8 |
| Total peak capacity | 99.3 | 102.0 | 104.0 | 104.7 | 101.9 | 113.6 | 120.9 | 130.0 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| CM eligible | 76.3 | 77.7 | 79.7 | 82.0 | 83.8 | 86.1 | 86.7 |
| Non-CM | 62.5 | 64.6 | 66.0 | 69.9 | 74.8 | 80.2 | 83.4 |
| Total peak capacity | 138.8 | 142.3 | 145.8 | 151.8 | 158.5 | 166.3 | 170.1 |

### Table 42: System Transformation generation capacity mix

| Capacity (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| CM eligible | 67.3 | 65.8 | 64.4 | 62.9 | 58.7 | 60.1 | 63.3 | 68.7 |
| Non-CM | 31.6 | 34.9 | 35.6 | 36.8 | 40.7 | 46.2 | 49.6 | 52.6 |
| Total peak capacity | 98.9 | 100.7 | 100.0 | 99.7 | 99.4 | 106.3 | 112.9 | 121.3 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| CM eligible | 69.6 | 71.7 | 73.7 | 74.8 | 76.6 | 77.1 | 75.7 |
| Non-CM | 53.9 | 57.7 | 56.3 | 65.2 | 66.8 | 77.5 | 80.6 |
| Total peak capacity | 123.4 | 129.4 | 130.1 | 140.0 | 143.4 | 154.6 | 156.3 |

### Table 43: Leading the Way generation capacity mix

| Capacity (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| CM eligible | 67.5 | 66.7 | 64.7 | 64.9 | 61.0 | 63.2 | 63.5 | 68.0 |
| Non-CM | 32.1 | 35.6 | 37.6 | 40.4 | 48.7 | 54.8 | 61.9 | 65.6 |
| Total peak capacity | 99.6 | 102.3 | 102.3 | 105.2 | 109.6 | 118.1 | 125.4 | 133.6 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| CM eligible | 69.2 | 69.1 | 72.1 | 74.3 | 75.7 | 79.7 | 80.2 |
| Non-CM | 68.1 | 76.9 | 79.2 | 83.7 | 86.0 | 87.6 | 90.2 |
| Total peak capacity | 137.2 | 146.0 | 151.3 | 158.0 | 161.8 | 167.3 | 170.4 |

### Table 44: Steady Progression generation capacity mix

| Capacity (GW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| CM eligible | 66.9 | 63.4 | 63.2 | 64.3 | 62.4 | 63.9 | 65.4 | 70.1 |
| Non-CM | 31.6 | 34.2 | 34.4 | 35.6 | 36.1 | 35.5 | 37.7 | 38.9 |
| Total peak capacity | 98.6 | 97.6 | 97.5 | 99.9 | 98.5 | 99.3 | 103.0 | 109.1 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| CM eligible | 71.8 | 72.2 | 73.5 | 75.7 | 78.5 | 81.1 | 82.4 |
| Non-CM | 47.0 | 52.4 | 51.5 | 52.3 | 53.3 | 53.0 | 55.7 |
| Total peak capacity | 118.9 | 124.6 | 125.0 | 128.1 | 131.8 | 134.0 | 138.2 |

## Data Behind 15 Year Horizon Chart

Table 45 contains the data behind Figure 14 showing the range in modelled CM-eligible de-rated capacity requirement in future years including any new / refurbished capacity secured in previous years. The Base Case is aligned to System Transformation from 2025/26 onwards.

**Table 45: Total CM-eligible De-rated Capacity required in Future Years**

| Capacity (GW) | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|
| Base Case | 48.5 | 48.3 | 47.6 | 47.1 | 45.7 | 47.0 | 48.6 |
| Consumer Transformation | 47.7 | 46.9 | 47.0 | 47.9 | 48.5 | 49.3 | 51.9 |
| System Transformation | 48.1 | 47.3 | 46.5 | 45.9 | 45.7 | 47.0 | 48.6 |
| Leading the Way | 45.5 | 44.8 | 43.7 | 43.5 | 43.8 | 42.5 | 45.1 |
| Steady Progression | 49.9 | 50.4 | 50.0 | 50.3 | 51.0 | 50.7 | 53.0 |
| Minimum | 45.5 | 44.8 | 43.7 | 43.5 | 43.5 | 42.5 | 45.1 |

| Capacity (GW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| Base Case | 47.8 | 47.6 | 48.1 | 47.9 | 47.5 | 45.3 | 43.8 |
| Consumer Transformation | 52.4 | 53.2 | 53.9 | 54.9 | 54.8 | 55.4 | 55.7 |
| System Transformation | 47.8 | 47.6 | 48.1 | 47.9 | 47.5 | 45.3 | 43.8 |
| Leading the Way | 45.6 | 45.3 | 45.1 | 45.5 | 45.4 | 46.0 | 45.8 |
| Steady Progression | 52.7 | 51.4 | 51.6 | 52.4 | 53.1 | 54.0 | 54.6 |
| Minimum | 45.4 | 45.2 | 45.1 | 45.5 | 45.0 | 42.8 | 41.3 |

### A.4.3 CM-ineligible Capacity

Table 46 gives a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2021/22 and 2024/25. The total capacity is lower than the nameplate capacity shown in A.4.2 since it is de-rated. Please note that the capacities by technology may not sum to the total ineligible capacity due to rounding.

**Table 46: Breakdown of De-rated CM ineligible capacity (GW) for 2021/22 and 2024/25**

| Generation type | 2021/22 Capacity (GW) | 2024/25 Capacity (GW) |
|---|---|---|
| Onshore Wind | 2.5 | 2.9 |
| Offshore Wind | 2.4 | 3.2 |
| Biomass | 3.8 | 4.0 |
| Autogeneration | 0.7 | 0.7 |
| Hydro | 1.1 | 1.0 |
| Landfill | 0.5 | 0.5 |
| Other | 1.4 | 1.6 |
| Total | 12.4 | 13.7 |

### A.4.4 Station Availabilities

As with the previous two years, small-scale/embedded CM-eligible technologies are mapped to the closest equivalent transmission-connected technology class, as required by the CM rules. For some small-scale non-CM technologies (for which availability values are modelling assumptions not prescribed by CM rules), we have amended the de-rating factors based on the best range of data sources available to us. Further development work and engagement with industry/government/regulator stakeholders will continue next year to improve the modelling of such small-scale embedded technologies that are connected at distribution level and for which we have no direct visibility.

Table 47 shows the station availabilities used for the 4 FES scenarios, Base Case and the High and Low availability sensitivities (rounded to the nearest %). The two sensitivities cover only the two most uncertain technologies: CCGT and Nuclear (existing) shown in bold in the table above.

**Table 47: Station availabilities by sensitivity**

| Technology type | | 2021/22 | 2024/25 |
|---|---|---|---|
| **CCGT** | Low availability sensitivity | **87%** | **87%** |
| | Base Case | **90%** | **90%** |
| | High availability sensitivity | **93%** | **93%** |
| **Nuclear (Existing)** | | | |
| | Low availability sensitivity | **77%** | **77%** |
| | Base Case | **81%** | **81%** |
| | High availability sensitivity | **86%** | **86%** |
| **Nuclear (New)** | | 90% | 90% |
| **Coal** | | 85% | 85% |
| **AD (incl CHP)** | | 70% | 70% |
| **Autogeneration** | | 90% | 90% |
| **Biomass** Dedicated/Conv./CCS/ CHP | | 85% | 85% |
| **EfW** | | 85% | 85% |
| **EfW CHP** | | 74% | 74% |
| **Gas CHP (large scale)** | | **As CCGT** | **As CCGT** |
| **Gas CCS** | | **As CCGT** | **As CCGT** |
| **Gas Turbine** | | 95% | 95% |
| **Geothermal (incl CHP)** | | 85% | 85% |
| **Hydro** | | 91% | 91% |
| **Landfill** | | 59% | 59% |
| **OCGT and Recip. Engines** | | 95% | 95% |
| **Oil** | | 95% | 95% |
| **Pumped storage*** | | 95% | 95% |
| **Sewage Gas** | | 49% | 49% |
| **Solar PV EFC** | | 2% | 2% |
| **Tidal and Wave** | | 22% | 22% |
| **Wind EFC** | | 19% | 19% |

*See Section 4.1 for de-rating factors for duration limited storage.

### A.4.4.1 Conventional Transmission Station Availabilities

Table 48 shows the station availabilities based on the mean of the last 7 winters (2013/14 – 2019/20) for each type of generation.

**Table 48: Station Availabilities**

| Generation Type | Availability |
|---|---|
| CCGT | 89.97% |
| OCGT | 95.22% |
| Coal | 84.80% |
| Nuclear | 81.43% |
| Hydro | 90.99% |
| Pumped Storage | 94.64% |
| Oil * | 97.12% |

* based on the 2 years for which data was available.

Previous comments[84] from BEIS's PTE stated that the availability of CCGT plant was low when compared to other markets with similar support mechanisms and recommended that National Grid ESO undertake analysis to benchmark CCGT and other technology availabilities from around the world.

Previously, National Grid ESO commissioned Arup, in 2014, to produce a report on the availability of plant, particularly CCGTs, in markets that incentivise availability. For the main generation technologies of CCGT, OCGT, coal and nuclear, Arup provided an availability assumption. Table 49 shows the two views of availabilities.

**Table 49: Availability Comparison**

| Generation Type | National Grid ESO | Arup |
|---|---|---|
| CCGT | 89.97% | 87% - 93% |
| OCGT | 95.22% | 94% |
| Coal | 84.80% | 87% |
| Nuclear (Existing) | 81.43% | 77% |

Based on the international benchmark data provided in Arup's report and further discussions with BEIS and the PTE, the availabilities for each type of generation have been revised to the values as shown in Table 50.

[84]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267624/Annex_E_-_PTE_draft_report_FINAL.pdf

**Table 50: Availabilities Used**

| Generation Type | Availability |
|---|---|
| CCGT Pre 2020/21 | 89.97% |
| CCGT 2020/21+ | 90.00% |
| OCGT | 95.22% |
| Coal | 84.80% |
| Nuclear (Existing) | 81.43% |

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

### A.4.5 Reserve for Response (to cover largest infeed loss)

National Grid ESO 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. Table 51 shows the reserve requirement to cover the largest in-feed loss[85] for each scenario. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held.

**Table 51: Reserve to cover largest infeed loss by scenario**

| In Feed Loss (MW) | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 |
|---|---|---|---|---|---|---|---|---|
| Base Case | 1500 | 1500 | 1600 | 1100 | 1100 | 1100 | 2400 | 2500 |
| Consumer Transformation | 1500 | 1500 | 1600 | 1100 | 1200 | 1200 | 2600 | 2600 |
| System Transformation | 1400 | 1500 | 1500 | 1100 | 1100 | 1100 | 2400 | 2500 |
| Leading the Way | 1500 | 1600 | 1600 | 1100 | 1100 | 2400 | 2400 | 2500 |
| Steady Progression | 1400 | 1400 | 1600 | 1000 | 1000 | 1000 | 1000 | 1000 |

| In Feed Loss (MW) | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 |
|---|---|---|---|---|---|---|---|
| Base Case | 2500 | 2500 | 2500 | 2500 | 2500 | 2600 | 2600 |
| Consumer Transformation | 2600 | 2600 | 2700 | 2700 | 2700 | 2700 | 2700 |
| System Transformation | 2500 | 2500 | 2500 | 2500 | 2500 | 2600 | 2600 |
| Leading the Way | 2400 | 2400 | 2400 | 2300 | 2300 | 2300 | 2300 |
| Steady Progression | 2300 | 2300 | 2300 | 2300 | 2200 | 2200 | 2200 |

[85] Note: the reserve for largest infeed loss above is not included in the peak demand values shown earlier

# A.5 Detailed Modelling Approach

Details for this section can be found in page 81 of ECR 2017.[86]

In addition to that information, we have also included further information on the assumptions that form the non-delivery and over-delivery sensitivities. We have also included information here on the sensitivities that were considered but not included in this year's analysis.

## A.5.1 Assumptions for the over-delivery and non-delivery sensitivities

Table 12, Table 13 and Table 14 summarise the components for the non-delivery and over-delivery sensitivities. These tables show the different types that we considered, the amount of each and the combination through the root sum of squares approach that results in the maximum value for each year. Table 52, Table 53 and Table 54 provide further commentary on these values.

**Table 52: Assumptions for 2021/22 T-1 non-delivery sensitivities. All values rounded to nearest 0.1.**

| Category | Discrete (GW) | Root sum of squares (GW) | Notes |
|---|---|---|---|
| Large thermal | 3.0 | 9.0 | ECR 2018 reported a development project on non-delivery in response to PTE recommendation 31. 3 GW large thermal (coal and gas) considered at risk due to challenging economic outlook |
| Nuclear | 0.9 | 0.8 | Two nuclear stations experienced extended outages covering winters 2018/19 and 2019/20. As de-rating factors in 2021/22 already assume more than one full station is unavailable, we only assume one additional station in non-delivery |
| Small-scale generation | 1.0 | 1.0 | We assume 1 GW based on changes to embedded benefits and environmental legislation that could potentially change the business case for small-scale generation. |
| Unproven DSR | 0.3 | 0.1 | 1.2 GW cleared in the 2021/22 T-4 auction and we assume 25% may not deliver based on failed meter tests in early delivery years |
| Interconnectors | 1.5 | 2.3 | Non-delivery based on combination of assuming interconnectors deliver in line with lower end of de-rating factor range (contributes around 0.7 GW) and that interconnector reliability (assumed 0.8 GW based on outages experienced in 2016/17) |
| **Sum of non-delivery** | **6.7** | **3.6** | **Note: 3.6 = square root of (9 + 0.8 + 1 + 0.1 + 2.3)** |
| Market response | -1.2 | -0.6 | Based on non-delivery development project reported in 2018 ECR, which identified 1 GW CCGT and 0.2 GW from interconnectors as potential market response. Market response for root sum of squares assumes same percentage as discrete case (i.e. 1.2 / 6.7 = 0.6 / 3.6) |
| **Total** | **5.5** | **3.0** | **2.8 when rounded to nearest 0.4 GW** |

[86] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

**Table 53: Assumptions for 2024/25 T-4 non-delivery sensitivities. All values rounded to nearest 0.1.**

| Category | Discrete (GW) | Root sum of squares (GW) | Notes |
|---|---|---|---|
| Large thermal | 2.0 | 4.0 | ECR 2018 reported a development project on non-delivery in response to PTE recommendation 31. 2 GW large thermal (gas) considered at risk due to challenging economic outlook. This is lower than assumed for the 2021/22 T-1, reflecting coal stations will have already closed. |
| Nuclear | 1.8 | 3.2 | Two nuclear stations experienced extended outages covering winters 2018/19 and 2019/20. As de-rating factors in 2024/25 donot fully cover the unavailability of one station in our Base Case, we assume two stations in non-delivery |
| Small-scale generation | 0.7 | 0.5 | We assume 0.7 GW based on changes to embedded benefits and environmental legislation that could potentially change the business case for small-scale generation. This is lower than the 2021/22 T-1 assumption as market participants have now had time to reflect these changes in their CM bidding strategy. |
| Unproven DSR | 0.4 | 0.2 | Around 1.5 GW cleared in the recent 2022/23 T-3 and 2023/24 T-4 auctions and we assume 25% may not deliver based on failed meter tests in early delivery years |
| Interconnectors | 1.5 | 2.3 | Non-delivery based on combination of assuming interconnectors deliver in line with lower end of de-rating factor range (contributes around 0.7 GW) and that interconnector reliability (assumed 0.8 GW based on outages experienced in 2016/17) |
| **Sum of non-delivery** | **6.4** | **3.2** | **Note: 3.2 = square root of (4 + 3.2 + 0.5 + 0.2 + 2.3)** |
| Market response | -1.2 | -0.6 | Based on non-delivery development project reported in 2018 ECR, which identified 1 GW CCGT and 0.2 GW from interconnectors as potential market response. Market response for root sum of squares assumes same percentage as discrete case (i.e. 1.2 / 6.4 = 0.6 / 3.2) |
| **Total** | **5.2** | **2.6** | **2.4 when rounded to nearest 0.4 GW** |

**Table 54: Assumptions for 2021/22 T-1 and 2024/25 T-4 over-delivery sensitivities. All values rounded to nearest 0.1.**

| Category | Discrete (GW) | Root sum of squares (GW) | Notes |
|---|---|---|---|
| Large thermal | 1.0 | 1.0 | Based on estimates of large thermal plant that could stay open without CM agreements. Mainly assumed to be gas, particularly for 2024/25 for which there will be limited opportunity for coal to remain open without a CM agreement |
| Nuclear | 0.0 | 0.0 | We assume nuclear stations will have a CM agreement for as long as they remain operational |
| Small-scale generation | 1.5 | 2.3 | Comparisons between our Base Case assumptions and capacity contracted in the CM (from 2017/18 to 2020/21) estimate that around 1.5 GW uncontracted distributed generation staying open. |
| Unproven DSR | 0.3 | 0.1 | Based on estimates of DSR without agreements from 2018/19 |
| Interconnectors | 1.0 | 1.0 | Assumes interconnectors deliver in line with the upper end of the modelled de-rating factor ranges |
| **Sum of non-delivery** | **3.8** | **2.1** | **Note: 2.1 = square root of (1 + 2.3 + 0.1 + 1)** |
| Market response | -1.0 | -0.5 | Based on analysis undertaken in a development project reported in 2018 ECR in response to PTE recommendation 31. Analysis identified potential market response of 0.6 – 0.7 GW from CCGT and 0.3 – 0.4 GW from interconnectors, resulting in a total of around 1 GW. In this case, the market response to over-delivery would lead to these contributions reducing. Market response for root sum of squares assumes same percentage as discrete case (i.e. 1.0 / 3.8 = 0.5 / 2.1) |
| **Total** | **2.8** | **1.5** | **1.6 when rounded to nearest 0.4 GW** |

### A.5.2 Sensitivities not included in this year's analysis

**Dependence of Generating Units** – The DDM implicitly assumes independence in availability of generating units. Several 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 in our modelling.

**Renewable Plant Non-Delivery** – This sensitivity was to reflect delays in delivering non-delivery from capacity not eligible for the Capacity Market (e.g. delays in building new capacity). However, as the Base Case and four scenarios in FES already reflect this uncertainty, it was not included in our modelling.

**Black Swan Events** – These are defined as events that 'deviate beyond what is normally expected of a situation and are extremely difficult to predict, being typically random and unexpected'[87], and which we consider to have very low probability but high potential impact. 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). However, for winters 2018/19 and 2019/20 two nuclear plants failed to return to full service so maybe this is not as certain as previously thought as the nuclear fleet nears the end of their operating lives. We have also considered extreme cold weather (e.g. January 1986/87) combined with low wind, but this would involve changing more than one element which violates the principles behind the sensitivities of only including credible outcome by changing one variable. Extreme weather events may be most likely to impact first the transmission and distribution systems; insofar as 'black swan' events impact generation, the first recourse would be to 'latent capacity' on the. Given this and the economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with BEIS and the PTE not to include any 'black swan' event sensitivities.

**CMU misalignment to TEC** – This sensitivity relates to the CMUs (Capacity Market Units) connection capacity being greater than TEC (Transmission Entry Capacity) values for some transmission connected stations so that when the de-rating factors are applied, they result in nearly 100% availabilities for many stations. This clearly puts security of supply at risk, as no plant is 100% available so the auction has under secured capacity. However, our modelling mitigates this risk by only using capacities based on TEC, so all our recommendations take account of this anomaly as best it can, with only the T-1 auction potentially under securing if the stations successful in that auction have CMUs greater than TECs. Hence, we have agreed not to include this sensitivity.

**Combined Sensitivities** – Several system operators around the world consider combined sensitivities within their process for calculating the required capacity to meet their respective reliability standards. Consequently, we investigated whether this was appropriate for the GB process, particularly in relation to the use of a potential hybrid approach (see the 2017 ECR). First of all, we considered the potential use of combined sensitivities within the LWR tool. We concluded that this would, if included, result in lower probability sensitivities such as combined sensitivities being given equal weightings as sensitivities with only one

[87] https://www.investopedia.com/terms/b/blackswan.asp

variable changed which would be inappropriate. Secondly, we considered it as part of the hybrid approach but to change the answer materially required such a low probability sensitivity that it may be considered more like a 'black swan' event and it was thus decided not to include it.

This was revisited again as a development project this year in response to recommendation 46 of the 2019 PTE report. This led to similar conclusions as those drawn in the work reported in the 2017 ECR supporting the decision not to include these events as sensitivities.

**Interruption to GB gas supplies** – A potential interruption to GB gas supplies could impact the availability of gas generation. However, as the likelihood of such an event is low, it has not been included in our modelling for the same reasons that we have not included other low probability or black swan events.

## A.6 Storage De-rating Factor Data Assumptions

As reported in Sections 2.4.3.3 and 4.1, we have calculated the de-rating factors for duration limited storage in the 2020 ECR based on an updated view of storage durations and capacities (see Table 55). Please note that given that this work was carried out before the storage capacity figures were finalised, the capacities in the table may differ slightly from the final values. In 2017, we ran an industry consultation[88] on the methodology and modelling assumptions for the new approach to de-rating the sub-categories of this technology type. The final de-rating factor number for each duration limited storage class sub-category is (amongst other modelling assumptions) influenced by each of the following methodology attributes:

- (EFC) The incremental Equivalent Firm Capacity (EFC) of a perfectly reliable storage unit (of each respective duration) and of a relatively small capacity added to the margin of a Base Case targeted at 3 hours LOLE, the GB Reliability Standard. The Base Case is set up to reflect the expected composition of the GB power system in each T-1 and T-4 target year in question. One key issue is that as indicated by our report to industry in 2017, then the assumption of the amount and composition of storage in the Base Case in each target year will influence the EFC of incremental storage units added thereafter – more shorter duration storage in the Base Case will tend to reduce the incremental EFC of storage units added thereafter. The assumptions in the 2020 ECR Base Case for the penetration of storage by capacity and duration are listed in Table 55 below.
- (TA-PS) The technical breakdown parameter to be applied to the storage technology class overall, namely that which is calculated as the historical technical availability of pumped storage over the last 7 years' winter periods - calculated as 94.64% this year
- The histogram of stress event durations of the same Base Case (see Figure 28 and Figure 29), whereby all durations above that duration threshold which corresponds to longer than 95% of potential stress events shall receive the same de-rating factor of pumped storage (TA-PS), and those that are shorter than this duration will receive a derating factor equivalent to the product of the incremental EFC and the technical availability of the storage class overall i.e. namely (EFC)*(TA-PS).

[88]https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

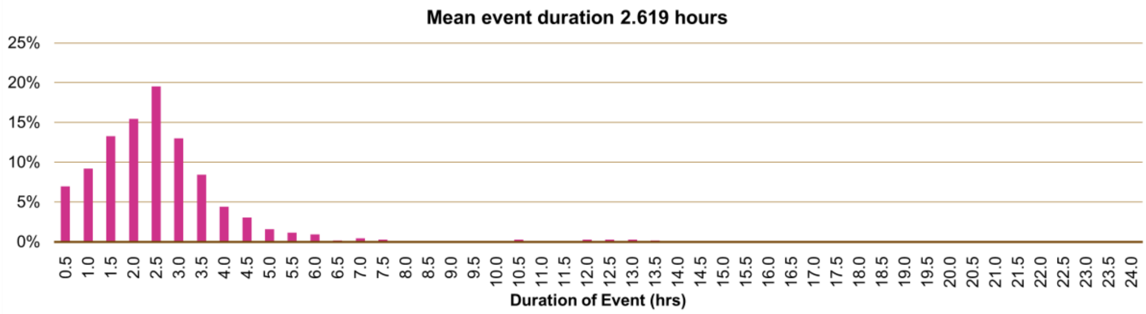
**Table 55: Base Case duration limited storage assumptions (near final)**

| Duration Category (Hours) | 2021/22 T-1 Capacity (MW) | 2024/25 T-4 Capacity (MW) |
|---|---|---|
| **0.5** | 519 | 1,067 |
| **1** | 882 | 1,091 |
| **1.5** | 122 | 152 |
| **2** | 4 | 9 |
| **3** | 5 | 5 |
| **4** | 50 | 65 |
| **6** | 2,004 | 2,004 |
| **20+** | 740 | 740 |
| **Total** | **4,327** | **5,133** |

This year, there is lower level of storage capacity in the 2020 ECR Base Case than in the 2019 ECR Base Case, particularly in the T- 4 year (even though the years have advanced by one) with a notable reduction in the shorter duration categories. This reduction reflects updated market information and in particular the storage units awarded capacity market agreements in recent auctions.

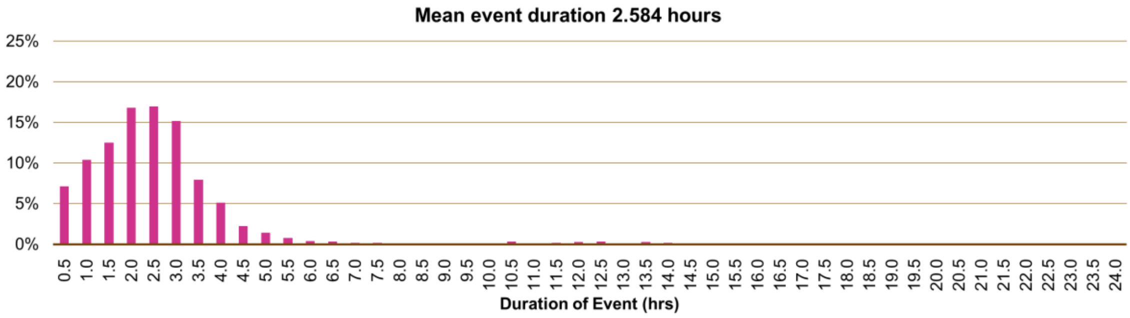
Due to the capacity reduction and, in particular, the reduced penetration of short duration storage of 1 hour or less, the de-rating factors in Table 16 have increased since the 2019 ECR particularly for the T-4 year. In addition, the duration threshold corresponding to 95% of stress events has reduced from 5.5 hours to 5 hours in the T-4 year showing that for cases adjusted to 3 hours LOLE, those with lower proportions of short-duration storage have a lower proportion of longer duration stress events. The distribution of stress events[89] is illustrated in Figure 28 and Figure 29.

**Figure 28: Stress Event Duration Histogram for 2021/22 T-1 Base Case at 3 hours LOLE**




[89] Please refer to 2017 storage de-rating industry consultation (pages 27 and 28) for caveats relating to these histograms: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

**Figure 29: Stress Event Duration Histogram for 2024/25 T-4 Base Case at 3 hours LOLE**




## A.7 Least Worst Regret

Details of Least Worst Regret approach and methodology can be found in page 87 of the 2017 ECR[90].

## A.8 ECR Recommendations and CM Auction Summary

Table 56 summaries the ECR recommendations, recommended demand curve target adjustments after prequalification, Secretary of State (SoS)'s decisions, capacity secured [91] (all in MW) and clearing prices (in £/kW) by auction.

**Table 56: ECR Recommendations and CM Auction Summary**

| Auction | ECR recommend -ation | SoS capacity set aside for T-1 | SoS Initial Target Capacity | Recommended Demand Curve adjustment after prequal. | Recommended target capacity after prequalification | SoS Final Target capacity | Capacity secured in auction | Auction clearing price |
|---|---|---|---|---|---|---|---|---|
| **TA 16/17** | N/A | N/A | 1,500 | N/A | N/A | 900 | 802 | £ 27.50 |
| **TA 17/18** | N/A | N/A | 300 | N/A | N/A | 300 | 312 | £ 45.00 |
| **EA 17/18** | 53,800 | N/A | 53,800 | -200 | 53,600 | 53,600 | 54,434 | £ 6.95 |
| **T-4 18/19** | 53,300 | 2,500 | 50,800 | -2,200 | 48,600 | 48,600 | 49,259 | £ 19.40 |
| **T-1 18/19** | 6,300 | N/A | 6,000 | -1,100 | 4,900 | 4,900 | 5,798 | £ 6.00 |
| **T-4 19/20** | 47,900 | 2,500 | 45,400 | -735 | 44,665 | 44,665 | 46,354 | £ 18.00 |
| **T-1 19/20** | 4,600 | N/A | 4,600 | -2,300 | 2,300 | 2,700 | 3,626 | £ 0.77 |
| **T-4 20/21** | 49,700 | 600 | 52,000 | -900 | 51,100 | 51,700 | 52,425 | £ 22.50 |
| **T-1 20/21** | 0 | N/A | 300 | -300 | 0 | 300 | 1,024 | £ 1.00 |
| **T-4 21/22** | 50,500 | 400 | 50,100 | -600 | 49,500 | 49,500 | 50,415 | £ 8.40 |
| **T-1 21/22** | 0 | | | | | | | |
| **T-3 22/23** | 45,400 | 1,200 | 44,200 | -200 | 44,000 | 44,000 | 45,059 | £ 6.44 |
| **T-4 23/24** | 44,700 | 1,200 | 43,500 | -400 | 43,100 | 43,100 | 43,749 | £ 15.97 |
| **T-4 24/25** | 41,600 | | | | | | | |

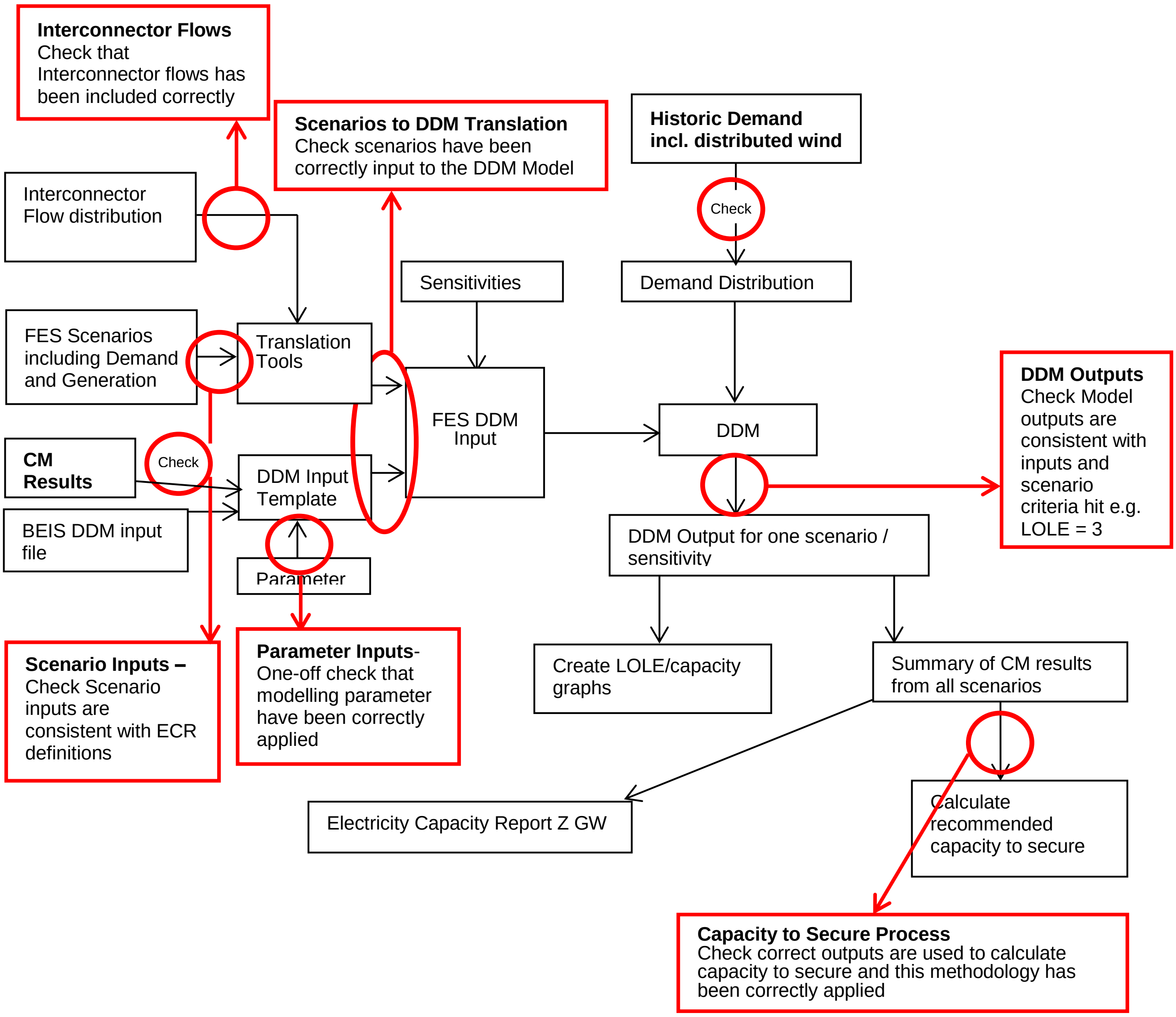
[90] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf
[91] Note that the capacity secured in the auction shown above may not be the same as the total secured capacity reported in the latest CM registers (e.g. due to terminations or metering tests for unproven DSR etc.)

## A.9 Quality Assurance

When undertaking any analysis, the Electricity System Operator (ESO) looks to ensure that a robust Quality Assurance (QA) process has been implemented. We have worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process[92]. 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 30: QA Checks Process Diagram for each Target Year**




[92] 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

The detailed QA process for each of these steps is described below.

### Interconnector flows

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

### Scenario Inputs

The FES process is driven by extensive stakeholder engagement[93], 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 ESO Executive Committee. The assumption and outputs will be published in the annual FES document on week commencing 27th July 2020.

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

### Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind

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

[93] http://fes.nationalgrid.com/media/1457/stakeholder-feedback-document-2020.pdf

## Scenarios to DDM Translation

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

## DDM Outputs

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

## QA Check List Process

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

## Capacity to Secure Process

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

## DDM model

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

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

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of DDM for ECR. In 2014, the owners of DDM, consultants Lane Clarke Peacock (LCP[94]), were asked to ensure that ESO was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between ESO 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 ESO is using the model correctly and correctly interpreting the output results.

## 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 Electricity System Operator with final sign off by the Director UK Electricity System Operator.

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

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