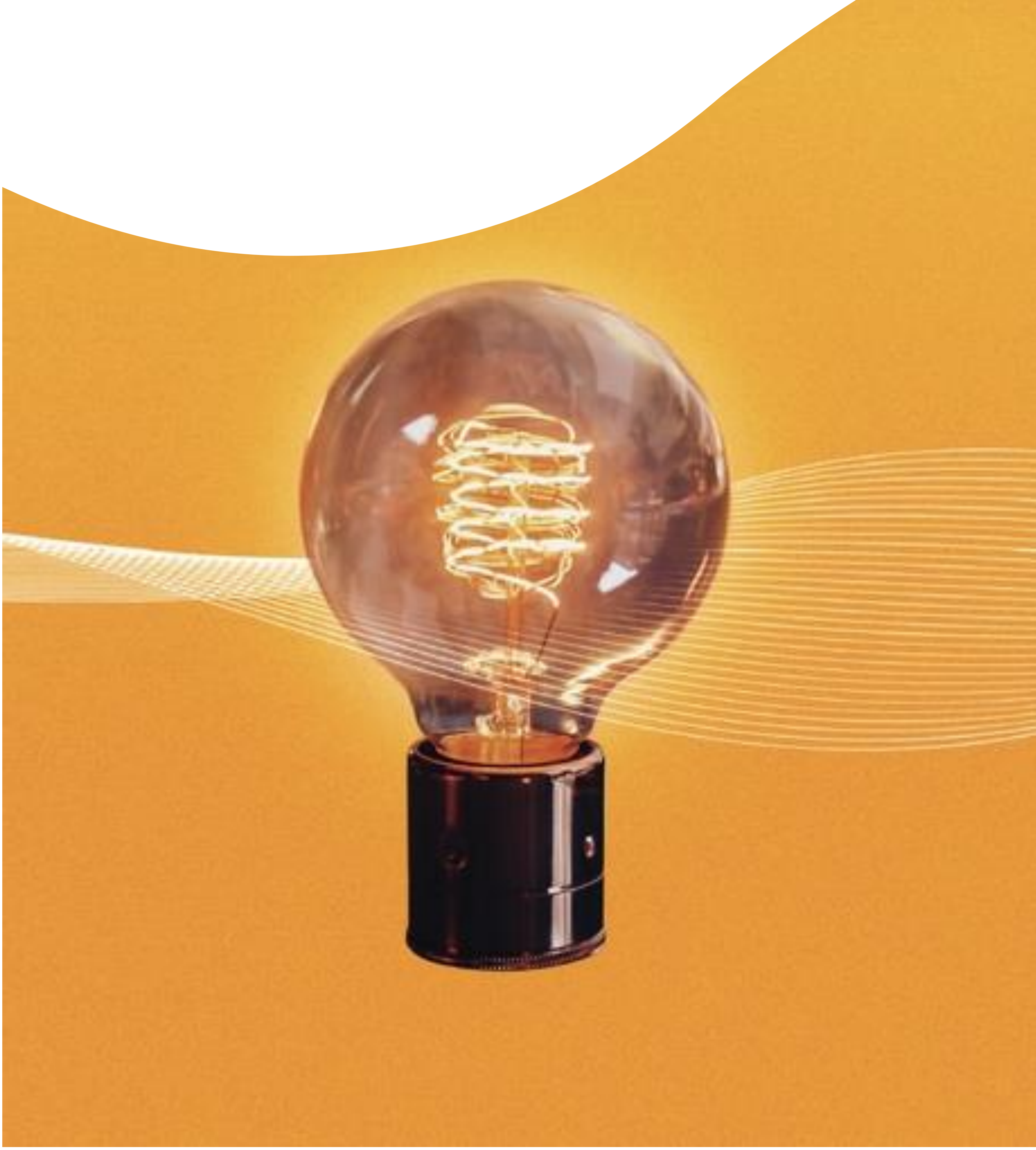
National Grid ESO Electricity Capacity Report

31 May 2021

(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

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 2022/23 and 2025/26.

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 2020 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 2022/23 T-1 and 2025/26 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.

1.1 Results and Recommendations

Table 1 shows National Grid ESO's recommendations for the target capacity for the 2021 auctions, T-1 delivering 2022/23 and T-4 for 2025/26. 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 delivery in 2022/23 and 2025/26 from the T-1 and T-4 Capacity Market auctions

	2022/23 T-1	2025/26 T-4
Recommended target capacity	4.5 GW	44.1 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.

[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/900062/panel-technical-experts-report-on-2020-electricity-capacity-report.pdf

Our modelling assumes that the Base Case and Future Energy Scenarios (FES) cover uncertainty in future electricity demand and supply. This includes uncertainty in peak demand, DSR, generation, storage and interconnection capacity (see Chapter 3).

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 2025/26, then aligned to System Transformation from 2026/27 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, 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[3]. 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 2022/23 T-1 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for the delivery in 2022/23 via the T-1 auction of **4.5 GW** derived from the requirement of the 2.4 GW non-delivery sensitivity. Our recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also accounts for any capacity already secured for delivery in 2022/23 from earlier T-3 and T-4 auctions that is assumed in the Base Case.

In general, when compared to the analysis for 2022/23 in the 2019 ECR, the 2021 ECR LWR outcome for 2022/23 is 3.3 GW higher than the 1.2 GW set aside by the Secretary of State for the T-1 auction. This net difference is the result of 5.9 GW of increases offset by 2.6 GW of decreases since the 2019 ECR.

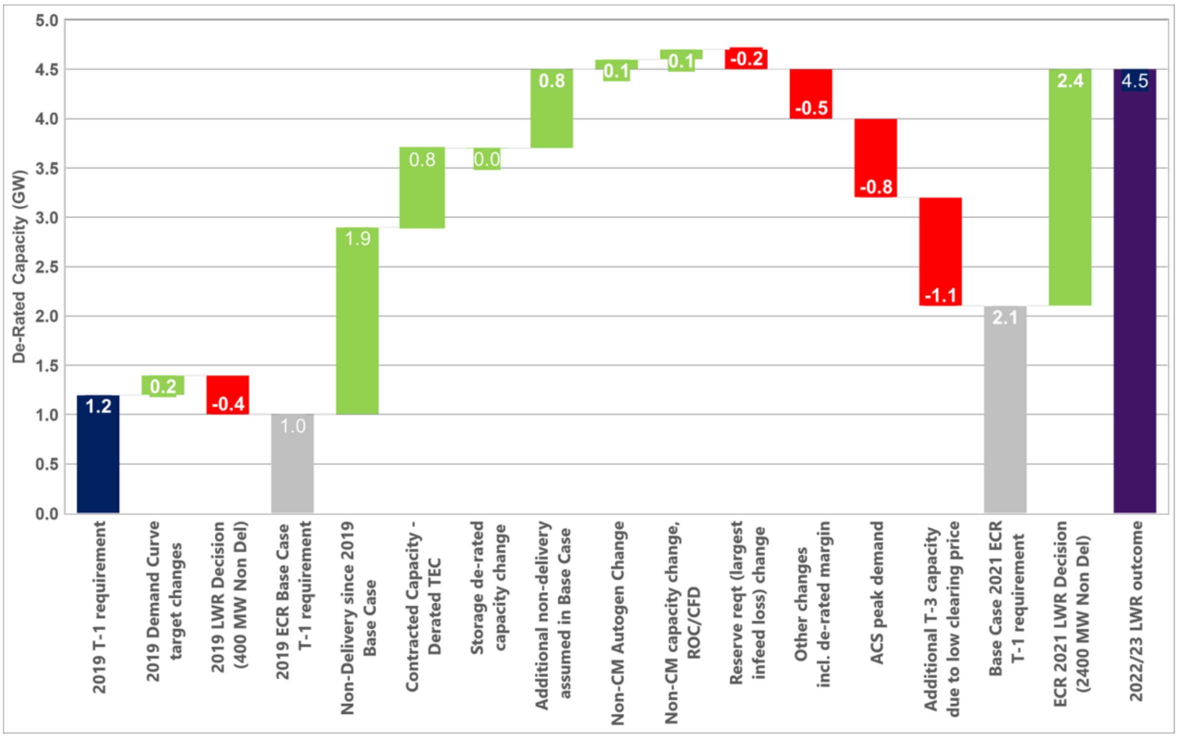
[3] Note that the Government's Reliability Standard was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT). For more information, see: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

The increases result from: known non-delivery (units in the 2019 Base Case awarded agreements in previous T-3 and T-4 auctions covering 2022/23 that are now known not to be able to honour their agreements); additional assumed non-delivery in the Base Case based on market intelligence of capacity providers who we do not currently expect to meet their obligations for 2022/23; the contracted capacity from previous T-3 and T-4 auctions being greater than the de-rated Transmission Entry Capacity (TEC); a small change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards; slightly lower levels of assumed opted-out or ineligible autogeneration; slightly lower non-CM renewable capacity than in the 2019 Base Case; and a change in the scenarios and sensitivities modelled resulting in a different LWR outcome than in 2019. In addition, the demand curve adjustments made in 2019 following prequalification for the T-3 auction (a reduction relating to long-term short term operating reserve (STOR) outside of the CM combined with a small increase due to non-CM autogeneration - 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 2021 Base Case generation assumptions are different to the 2019 Base Case assumptions.

The decreases arise from: a lower reserve for largest infeed loss; a lower peak demand for 2022/23 (see Section 5.3.3 for more details); a reduction due to over-securing in the 2022/23 T-3 auction and a net reduction due to other changes.

Figure 1 shows how the original 1.2 GW set aside for delivery in 2022/23 via the T-1 auction (derived from the 2019 0.4 GW non-delivery sensitivity) has changed into a LWR outcome of 4.5 GW (derived from the 2021 Base Case 2.4 GW non-delivery sensitivity) as a result of the net increase described above.

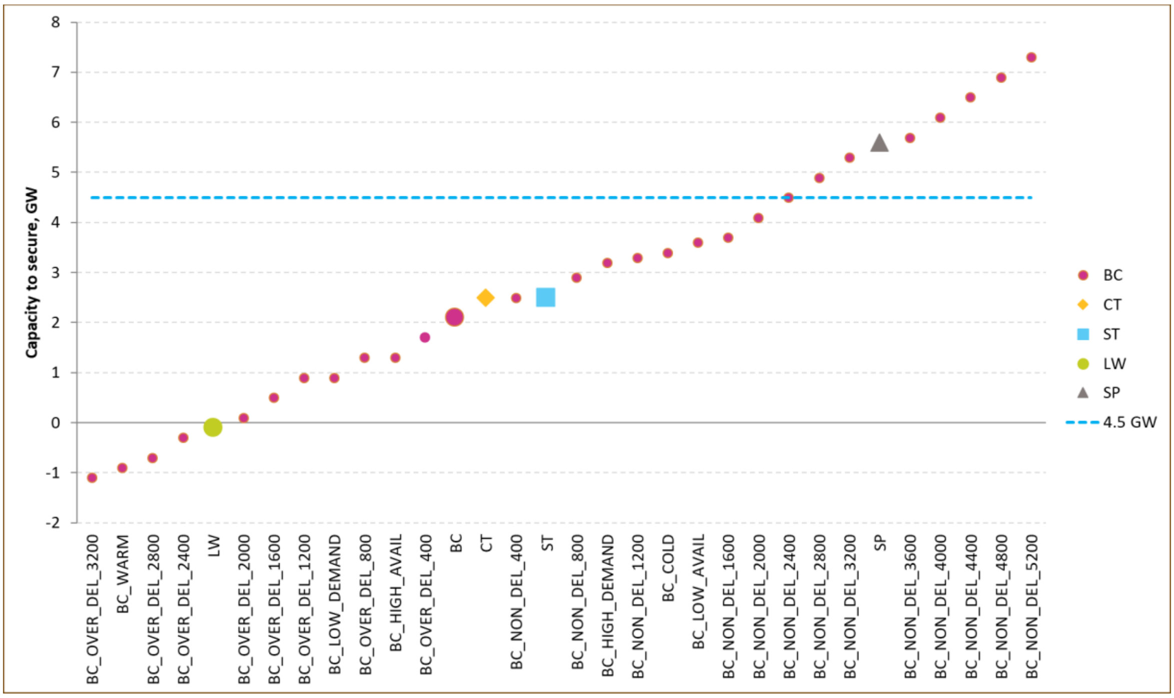
Figure 1: Comparison with original 2022/23 T-1 requirement (de-rated)



Note: intermediate totals in grey above show requirements for 2019 Base Case and 2021 Base Case

Figure 2 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 4.5 GW derived from the LWR outcome.

Figure 2: Least Worst Regret outcome and recommended capacity to secure compared to individual scenario / sensitivity runs – 2022/23



1.1.2 2025/26 T-4 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for the delivery in 2025/26 via the T-4 auction of **44.1 GW** derived from the requirement of the 2.8 GW non-delivery sensitivity. Our recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also accounts for any capacity already secured for delivery in 2025/26 via earlier T-3 and T-4 auctions that is assumed in the Base Case.

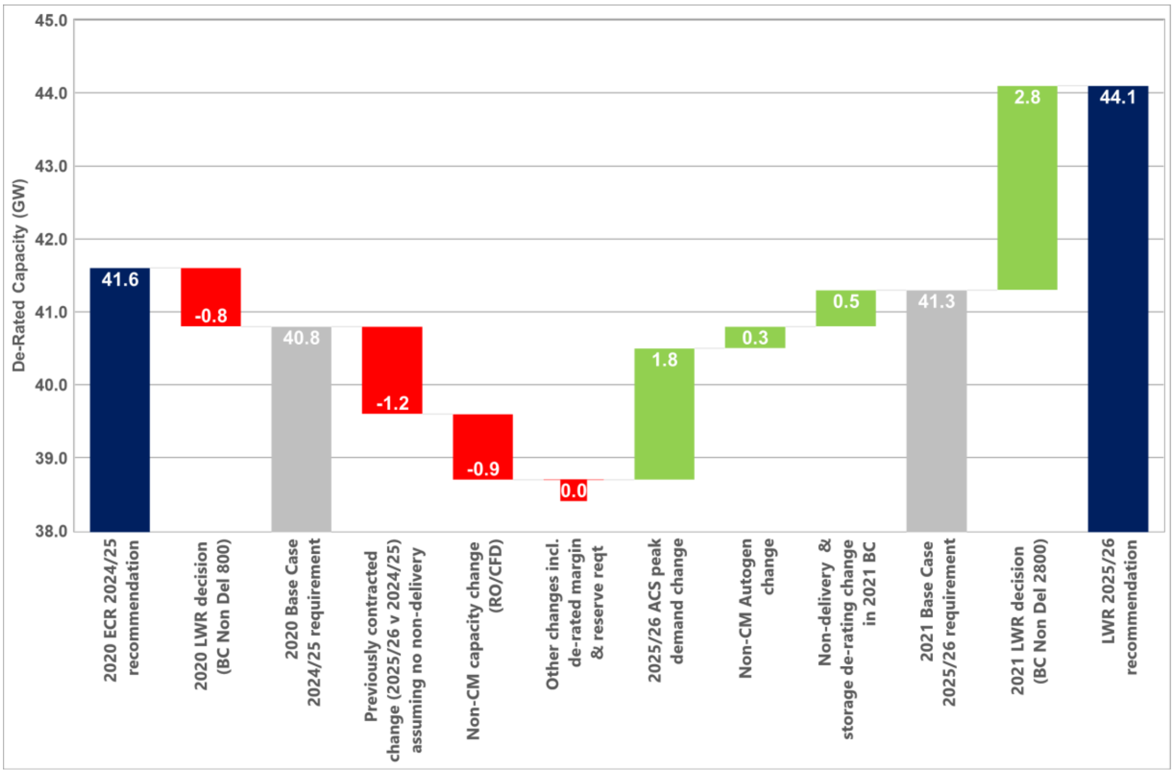
When compared to the analysis for 2024/25 in the 2020 ECR, the 2021 ECR recommendation for 2025/26 is 2.5 GW higher. This net difference is the result of 4.6 GW of increases offset by 2.1 GW of decreases since the 2020 ECR.

The increases result from: a higher peak demand for 2025/26 than for 2024/25 in the 2020 ECR (see Section 3.3 for more details); lower assumed opted-out or ineligible autogeneration; additional non-delivery assumed in the Base Case; a small change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards; a change in the scenarios; and sensitivities modelled resulting in an increased LWR outcome compared to the Base Case than in 2020.

The decreases arise from: an increase in previously contracted capacity from CM units awarded multi-year agreements in recent auctions (excluding the additional non-delivery assumed in the Base Case); higher non-CM renewable capacity; and a small net decrease due to other changes.

The waterfall chart in Figure 3, shows how the original 41.6 GW requirement for delivery in 2024/25 from the T-4 auction (derived from the 2020 Base Case 0.8 GW non-delivery sensitivity) has changed into a recommendation of 44.1 GW as a result of the 2.5 GW net increase described above.

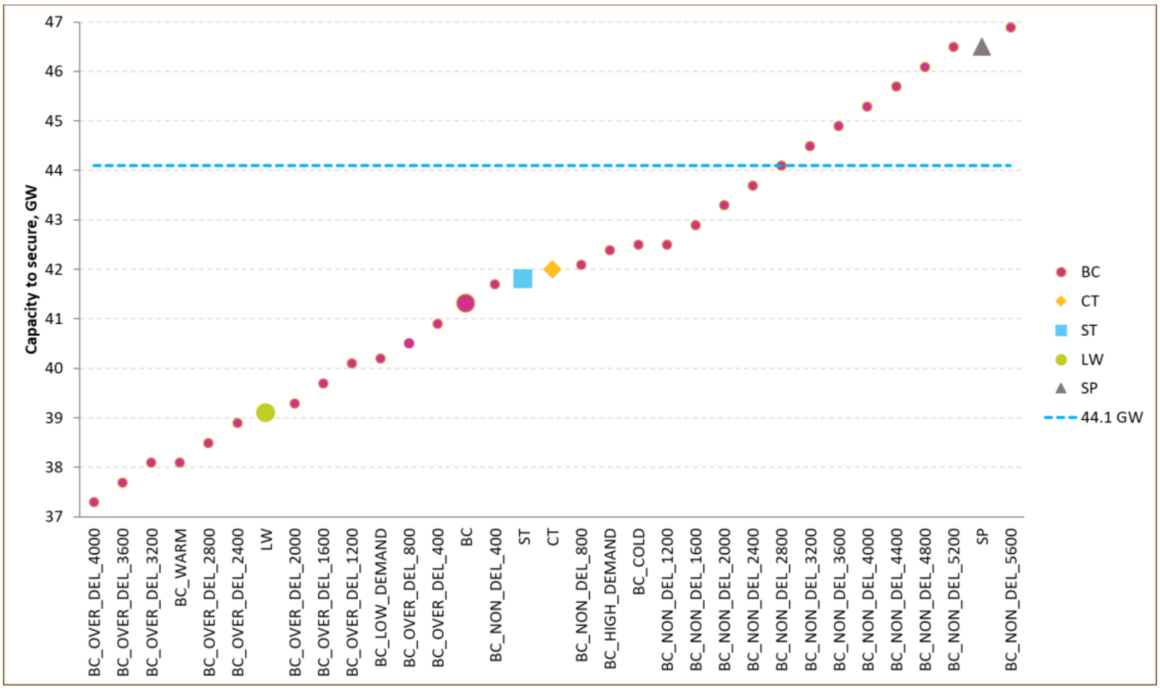
Figure 3: Comparison with recommended 2024/25 T-4 requirement in 2020 ECR



Note: intermediate totals in grey above show requirements for 2020 Base Case and 2021 Base Case

Figure 4 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 44.1 GW derived from the LWR outcome.

Figure 4: Least Worst Regret recommended capacity to secure compared to individual scenario / sensitivity runs – 2025/26



1.2 Interconnected Countries De-rating Factor Ranges

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 T-4 auction for 2025/26 delivery (all interconnectors that appear in the scenarios for the T-1 2022/23 delivery period have already been awarded agreements from the T-3 for 2022/23 auction).

In this year's modelling, we have continued to use the methodology used in ECR 2020 for calculating 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 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 that has been 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 has been undertaken as part of the Clean Energy Package (Article 26 of Regulation (EU) 2019/943). The methodology has now been approved and details can be found on the European Union Agency for the Cooperation of Energy Regulators (ACER) website[4].

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.

[4] https://www.acer.europa.eu/Media/News/Pages/ACER-decides-on-common-rules-for-cross-border-participation-in-electricity-capacity-mechanisms-.aspx

Table 2: Modelled de-rating factor ranges for interconnected countries

Country	ECR 2020 2024/25 T-4		ECR 2021 2025/26 T-4	
	Low	High	Low	High
Belgium	46	88	22	82
Denmark	45	80	47	87
France	50	91	59	97
Germany	54	83	43	79
Ireland	24	66	10	97
Netherlands	48	84	49	88
Norway	91	100	78	96

Note: De-rating factor ranges from the 2020 ECR are shown for comparison.

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. 2020 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 de-rating factors for distribution-connected generation (please see Section 2.5 for further information).

Table 3: De-rating factors for conventional plants

Technology Class	Plant Types Included	ECR 2020	ECR 2021*
Oil-fired steam generators	Conventional steam generators using fuel oil	95.22%	95.47%
Open Cycle Gas Turbine (OCGT)	Gas turbines running in open cycle fired mode	95.22%	95.47%
Reciprocating engines (non-autogen)	Reciprocating engines not used for autogeneration	95.22%	95.47%
Nuclear	Nuclear plants generating electricity	81.43%	80.44%
Hydro (excl. tidal / waves)	Generating Units driven by water, other than such units: a) driven by tidal flows, waves, ocean currents or geothermal sources; or b) which form part of a Storage Facility	90.99%	91.15%
CCGT	Combined Cycle Gas Turbine plants	90.00%	90.92%
CHP and autogen	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%	90.92%
Coal	Conventional steam generators using coal	84.80%	80.11%
Biomass	Conventional steam generators using biomass	84.80%	88.55%
Energy from Waste	Generation of energy from waste, including generation of energy from: a) conventional steam generators using waste; b) anaerobic digestion; c) pyrolysis; and d) gasification.	84.80%	88.55%
DSR[5]		79.21%	78.45%

* De-rating factors apply to both the 2022/23 T-1 and 2025/26 T-4 auctions.

Table 4: De-rating factors for duration limited storage

<table>
<tr><th>Duration (hours)</th><th>ECR 2020 2021/22 T-1</th><th>ECR 2020 2024/25 T-4</th><th>ECR 2021 2022/23 T-1</th><th>ECR 2021 2025/26 T-4</th></tr>
<tr><td>0.5</td><td>12.75%</td><td>12.38%</td><td>12.94%</td><td>9.98%</td></tr>
<tr><td>1.0</td><td>25.32%</td><td>24.77%</td><td>25.87%</td><td>19.96%</td></tr>
<tr><td>1.5</td><td>37.71%</td><td>36.97%</td><td>38.62%</td><td>29.94%</td></tr>
<tr><td>2.0</td><td>49.17%</td><td>48.62%</td><td>50.63%</td><td>39.73%</td></tr>
<tr><td>2.5</td><td>58.23%</td><td>58.78%</td><td>60.61%</td><td>48.97%</td></tr>
<tr><td>3.0</td><td>64.70%</td><td>66.18%</td><td>67.82%</td><td>56.18%</td></tr>
<tr><td>3.5</td><td>68.76%</td><td>70.98%</td><td>72.25%</td><td>61.54%</td></tr>
<tr><td>4.0</td><td>71.35%</td><td>73.76%</td><td>74.84%</td><td>64.86%</td></tr>
<tr><td>4.5</td><td>73.20%</td><td>75.79%</td><td rowspan="3">94.61%</td><td>67.45%</td></tr>
<tr><td>5.0</td><td rowspan="2">94.64%</td><td rowspan="2">94.64%</td><td>69.48%</td></tr>
<tr><td>5.5+</td><td>94.61%</td></tr>
</table>

[5]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 5: De-rating factors for renewables

Technology Class	ECR 2020 2021/22 T-1	ECR 2020 2024/25 T-4	ECR 2021 2022/23 T-1	ECR 2021 2025/26 T-4
Onshore Wind	8.01%	7.81%	7.81%	6.25%
Offshore Wind	12.11%	11.13%	11.33%	8.59%
Solar PV	2.54%	2.34%	2.15%	3.32%

This year, there is a lower level of storage capacity in the 2021 ECR Base Case than in the 2020 ECR Base Case in the T-1 year (even though the T-1 years have advanced by one) and a higher level in the T-4 year (see Annex A.6 for more details). As a result, the duration threshold corresponding to 95% of stress events has reduced from 5 hours to 4.5 hours in the T-1 year and increased from 5 hours to 5.5 hours in the T-4 year, resulting in step changes in the de-rating factors for these durations in those years in Table 4.

2. The Modelling Approach

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

2.1 High Level Approach

The modelling approach is guided by the policy and 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)[6]?

Following consultation with BEIS and the PTE, it was agreed that the Dynamic Dispatch Model (DDM)[7] 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 output LOLE values as National Grid ESO's capacity assessment model, when given the same inputs, which provides evidence that its security of supply calculations are robust.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[8] 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, sometimes referred to as consumer demand. '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 2035/36. 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

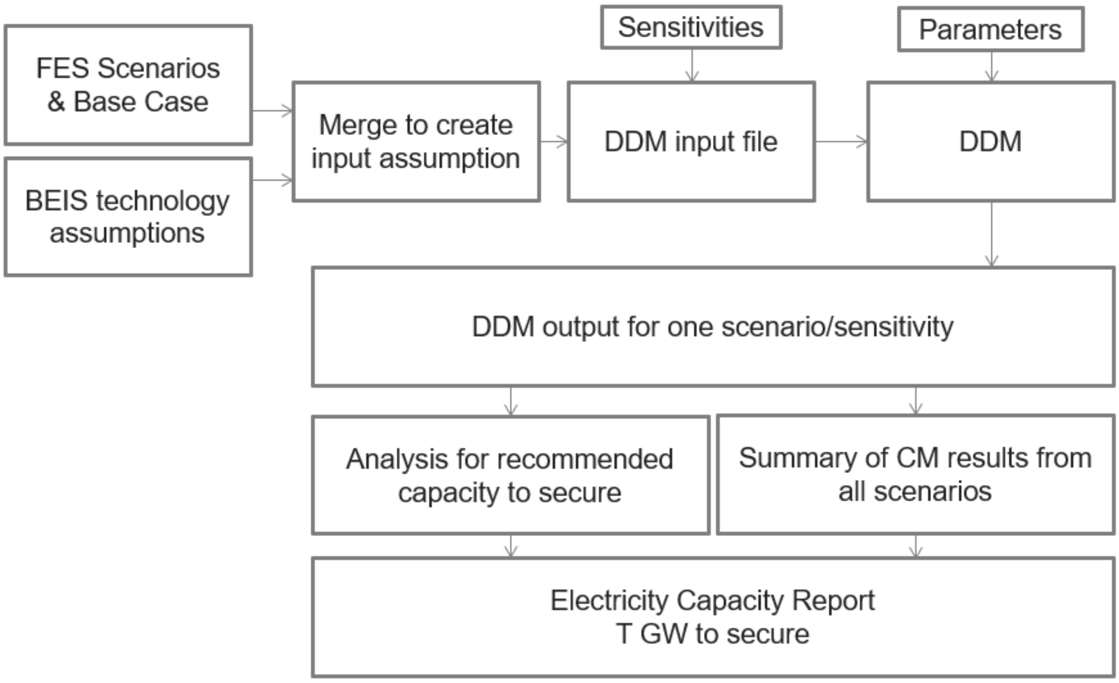
[6] LOLE is the expected number of hours when demand is higher than available generation during the year, before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

[7] DDM Release 6.1.28.1 was used for this analysis

[8] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

sensitivity modelled. The capacity to secure for each of these cases is then considered together to produce a recommended capacity to secure for delivery in 2022/23 T-1 and T-4 for 2025/26. Further details describing this can be found in Annex A.5.

Figure 5: Process flow chart of approach to calculate target capacity to secure (T) 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 for years 2022/23 and 2025/26. These values are used in the Least Worst Regret (LWR) calculation to produce the recommended target capacity (T) 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 – the core supply and demand assumptions that underpin the analysis in the ECR. 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[9] in line with our licence condition. The document, published annually in February, shows how stakeholder feedback informs the scenario framework and the 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 annual CM Launch Event and bilateral meetings. It also includes industry consultations on changes to the methodologies used to calculate technology de-rating factors when required (e.g. renewables[10] and duration limited storage[11]).

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 relating to demand and generation; interconnectors; and station availability, for the simulations to run. Further details on these assumptions are explained in this section.

2.4.1 Demand and Generation

The demand and generation assumptions are based on those used in BEIS' modelling[12] (e.g. technology assumptions for generation levelised costs). This forms the basis of our DDM input file. We update some of these assumptions (e.g. annual and peak demands, generation capacities, technologies and start dates) in the DDM input file to match those the latest FES, Base Case and sensitivities. The key assumptions that have a material impact on the capacity to secure include:

- Demand Forecasts
  - Peak demand (plus reserve for largest infeed loss)
  - Annual demand
- Generation Capacity
  - Capacity eligible for the Capacity Market
  - Capacity outside the Capacity Market (including capacity secured via previous auctions)

[9] https://www.nationalgrideso.com/document/187746/download
[10] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf
[11] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf
[12] https://www.gov.uk/government/collections/energy-generation-cost-projections

    - Capacities of existing and new interconnectors
- Station availabilities and de-rating factors by technology

The data for these assumptions is provided in Annex A.4.

2.4.2 Interconnectors

Interconnector capacities are based on those in the latest FES and Base Case, which considers both existing and new interconnectors. The latest FES and Base Case capacity assumptions are provided in Section 3.9.

We use a probabilistic distribution of interconnector flows in the DDM to model the contribution of interconnectors to GB at peak times for each scenario and delivery year. The distribution is derived from our pan-European market modelling in BID3[13] and assigns probabilities to different import / export levels for a given net system margin. The DDM combines this distribution with probability distributions for conventional generation, wind and demand to calculate a net system margin distribution. The DDM uses the net system margin distribution to calculate an Equivalent Firm Capacity (EFC) for interconnection, which is used as an estimate of the total de-rated interconnector capacity in that scenario and delivery year for the purpose of calculating the total de-rated capacity required to meet 3 hours LOLE. The interconnection EFC values for the Base Case in the T-1 and T-4 year are provided in Annex A.4.4.

The interconnection EFC can impact the capacity to meet 3 hours LOLE for the T-1 year. This is because the interconnection EFC may differ from the de-rated interconnector capacity previously contracted in the corresponding T-4 auction. If the interconnection EFC is lower than the previously contracted capacity, then the DDM will treat this as non-delivery and increase the T-1 capacity requirement. If the interconnection EFC is higher than the previously contracted capacity, the surplus is assumed to enter the T-1 auction and so does not impact the T-1 capacity requirement. The interconnection EFC does not impact the T-4 capacity requirement since no interconnectors have been previously contracted.

In the 2020 ECR, the interconnection EFC was significantly lower than the previously contracted interconnector capacity. This arose because the interconnector flow distributions had not been updated in the DDM for the ECR modelling due to a change in the interconnector de-rating factor methodology. This was corrected when we carried out the Adjustment to the Demand Curve after prequalification and we have since undertaken a development project to ensure that the distributions have been updated for the 2021 ECR. We are confident that this issue has now been resolved with no further change required.

In addition to this modelling work, National Grid ESO provide modelled ranges of de-rating factors 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.

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

2.4.3 Station Availabilities and De-rating Factors

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[14]. The DDM uses the availabilities to create a conventional generation distribution on the basis that each unit is assumed to be fully on with a probability equal to its availability and is assumed to be fully off with a probability equal to one minus its availability. The method used to calculate the station availabilities is consistent with the methodology for conventional generation de-rating factors described in Section 2.3.5 of the Capacity Market Rules.[15]

The data for the station availability assumptions is provided in Annex A.4.

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). We assess their expected contribution to security of supply by calculating their EFC for the entire winter period.

The wind EFC is calculated using historic data of observed wind speeds across Great Britain. We use wind power curves to convert wind speeds into wind output generation, which is used to determine the EFC, which 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 the amount of installed wind capacity, its geographical location and the amount of wind that might be expected at times of high demand. It also depends on how tight the overall system is. If the system is tighter, there are more periods in which wind generation is preventing loss of load rather than displacing other types of generation in the merit order, and so the EFC is higher. We should stress that the wind EFC is not an assumption or prediction of wind output at peak times and should not be treated as such. The wind EFC is calculated by the DDM and is therefore an output of our modelling. The wind EFC values for the Base Case are provided 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 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. 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[16].

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[14] 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 peak demands for that winter
[15] https://www.gov.uk/government/publications/capacity-market-rules
[16] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

We should note that the wind and solar EFCs used in the DDM to determine the auction target capacity are different to the recommended auction de-rating factors. This is because the EFC values used in the DDM include the contribution from the entire wind and solar fleet. The de-rating factors for the auction are based on incremental EFCs for wind and solar, which represents the contribution to security of supply brought by delivering any additional wind and solar via the Capacity Market.

Impact of availability assumptions

Given that the recommended capacity to secure is a de-rated value, the assumptions around the availability of eligible technologies have a limited impact on the capacity required in the T-4 runs[17]. For the T-1 runs, changes to eligible technology availability assumptions may have an impact on the contribution of capacity contracted in previous auctions, which we account for in the low and high availability sensitivities. However, such changes have a limited impact on our recommendation for the T-1 year as the low and high availability sensitivities do not set the extremes of the Least Worst Regret range. For ineligible capacity (such as those outlined in Reg. 16 of the Electricity Capacity Regulations), changes in availability assumptions may have an impact on our recommendations as the ineligible capacity is netted off the target, but such impacts are usually small as year-on-year changes in these availability assumptions are small and the ineligible capacity is a relatively small proportion of the total capacity required to meet 3 hours LOLE.

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 areas 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 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 2020/21 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 were then taken forward.

[17] 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

2.5.2 Key projects undertaken

In their 2020 report[18], PTE made six new recommendations numbered 52 to 57, each of which were considered as a potential development project for prioritisation alongside others. Recommendations 56 and 57 have not been completed. Recommendation 56 relates to the technical reliability of HVDC links, which is particularly important for interconnectors. While we recognise the importance of this, the recommendation requires further consideration on how best to take it forward. Recommendation 57 relates to how our T-4 recommendation is used to secure capacity via a T-4 and a T-1 auction. Our recommendation at T-4 does not explicitly consider the nature of having two opportunities to secure capacity. This led to concerns raised by the PTE as to whether there was a systematic bias in the process that didn't reflect the opportunity of having the T-1 auction – a view potentially supported by consecutive recommendations in the 2019 and 2020 ECRs of 0 GW for the T-1 target capacity. Discussions involving National Grid ESO, BEIS, the PTE and Ofgem identified that this to be a potentially more complex task than initially envisaged. The scope potentially covers: determining the T-1 set-aside, the slope of the demand curve in the T-4 auction; auction liquidity and whether the modelling could reflect more of the uncertainty stochastically that could reduce the dependence on sensitivities and the Least Worst Regret calculation. Even though the final 2021/22 T-1 auction target and our T-1 recommendation for delivery in 2022/23 are both greater than zero, we think there is still merit in exploring this further next year and will continue to work with BEIS, Ofgem and the PTE to better define a scope of work to consider taking forward. 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.

ESO Demand Modelling

The peak demand forecast is one of the most important assumptions that impacts the auction target capacity. This has been recognised by the PTE and led to recommendation 52 in their 2020 report. Every year, National Grid ESO has taken steps to improve its peak demand forecast. In addition to the Demand Forecast Accuracy incentive, we have also been required to set out the steps taken to improve the peak demand forecast in a letter to Ofgem under Special Condition 4L.13[19].

Demand forecasting has been particularly challenging this year in light of the ongoing COVID-19 pandemic. The timing of the modelling for the 2020 ECR meant that the impact of COVID-19 was not included in the peak demand assumptions. National Grid ESO undertook additional analysis last year to assess how the impact of the COVID-19 could have impacted our assumptions in the 2020 ECR. This assessment informed our recommendations on the target capacity for the T-1 auction for delivery in 2021/22 when we published our Adjustment to the Demand Curve in January 2021. Details of our demand assumptions were also published on our website[20].

Chapter 3 sets out our latest demand forecasts and the assumptions that underpin them.

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18 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/900062/panel-technical-experts-report-on-2020-electricity-capacity-report.pdf

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/Capacity%20Markets%20Document%20Library/FES%2020%20Covid-19%20Update%20-%20February%202021%20V1.pdf

Embedded Generation De-rating Factors

Capacity market units (CMUs) require a de-rating factor to participate in the CM auctions. The de-rating factor reflects the expected contribution to security of supply for each CMU based on its technology class. The current methodology, prescribed in Section 2.3 of the CM rules[21], means that data from transmission-connected generation is used to calculate de-rating factors for all conventional generating technologies. However, there are some technologies where generating units are predominantly embedded in the distribution networks (e.g. reciprocating engines). Historically this hasn't been possible as such data hasn't been available to National Grid ESO. In recent years, National Grid ESO has sought to obtain better data that might enable de-rating factors for generating technologies predominantly connected to the distribution networks to be calculated directly from embedded generation data. This data includes half-hourly metered generation output data procured through a bilateral contract with Electralink and the Embedded Capacity Registers published on Distribution Network Operator (DNO) websites that sets out the assets connected in each area. This new data opened the possibility of determining de-rating factors for embedded technologies directly and led to recommendation 53 in the 2020 PTE Report.

In this project, National Grid ESO undertook a validation exercise to match the new data to our current baseline assumptions and then explore whether it could be used to determine de-rating factors. This work was undertaken in Q3 2020/21 and discussed with BEIS, Ofgem and the PTE in Q4 2020/21.

The project considered three alternative approaches that could be used to determine de-rating factors for embedded technologies. The outcome showed that while the three different approaches yielded similar results as the existing methodology, there are two areas that need further consideration ahead of any potential industry consultation. Firstly, the data validation exercise highlighted that better data quality, particularly on improving the match to our existing baseline assumptions, would provide greater confidence in the robustness of any alternative methodology. Secondly, the alternative methodologies relied on using output generation as a proxy for availability. This requires further thought since it is possible that a generator could be available, but its output is zero. Such events would potentially underestimate the technology's contribution to security of supply and their auction de-rating factor. We would also need to consider the implication of a de-rating factor methodology based on output generation for technology's whose behaviour in the market (and hence output generation) could change over time.

Since this work was completed, we have continued to work closely with the DNOs to improve the data in the Embedded Capacity Registers, particularly on aligning technology types of assets. We would therefore expect a much better match to our existing baseline that would enable us to develop recommendations on possible alternative methodologies on which we could consult with industry ahead of the 2022 ECR.

We have published a paper on the analysis to-date and invite feedback from industry stakeholders[22]. We particularly welcome the opportunity to engage at this point, as this could help us better reflect stakeholder views in our work before we reach the consultation stage.

[21] https://www.gov.uk/government/publications/capacity-market-rules
[22] To be published at https://www.emrdeliverybody.com/cm/home.aspx

Assessment of over-delivery for Base Case / sensitivities

In their 2020 report, the PTE commented that the assumption that all eligible plants will enter the CM or shut may no longer hold true and may need to be accounted for more explicitly. This led to recommendation 54. We carried out an assessment to estimate the potential CM-eligible capacity that remained operational in each winter from 2017/18 to 2020/21 without a CM agreement (e.g. it either chose not to participate in the CM or was unsuccessful in gaining an agreement in the auction or via secondary trading). We refer to such capacity as over-delivery. The development project also considered different situations that could lead to over-delivery. The outcome of the project recommended that there may be a small amount of over-delivery that could be assumed in the Base Case for T-1 but not for T-4 due to more uncertainty and likely closure of existing stations. We have therefore assumed an additional 0.4 GW over-delivery in our modelling for 2022/23. The project also supported continued use of existing ranges for over-delivery sensitivities, described in Section 3.10.5.

European Modelling Assumptions

In the 2020 ECR, we introduced a change to the methodology used to determine the de-rating factor ranges for interconnected countries. While the PTE considered the new approach to be more robust, they expressed a desire for us to be more transparent in our modelling assumptions and how they could bias the de-rating factors. This led to recommendation 55 in their 2020 report. We have reviewed our modelling assumptions and provided further information to the PTE on the key assumptions and their limitations. We have also included further detail on our modelling assumptions in Annex A.10 to provide greater transparency to all stakeholders. The nature of the pan-European market model means that we are unable to publish details of every assumption – there are simply too many. There are also some assumptions that we procure through bilateral contracts with Afry, which we are also unable to publish. However, we welcome feedback on the additional information that we have published.

2.6 Modelling Enhancements since Last Report

In addition to the previously described development projects, we have also carried out a development project to update the interconnection probability distributions used in our DDM modelling. This has corrected the misalignment reported in the 2020 ECR between the interconnection EFC and the previously contracted interconnection capacity in the T-1 runs[23]. The updated methodology for producing these distributions better matches the methodology used in the interconnection de-rating factor modelling (described in Section 2.4.2). We have also made some changes to the sensitivities modelled to better reflect the range of uncertainties (see Section 3.10).

The 2019 PTE report[24] made a recommendation (number 42) relating to the modelling of smaller generators recognising that many smaller units can provide greater reliability than fewer large units through their greater diversity. This recommendation was carried forward in the 2020 PTE report, noting that the recommendation had been partly addressed. In previous ECRs, we modelled large transmission units individually, but distributed generation capacity was aggregated by technology into blocks of capacity. Further progress

[23] See Section 2.4.2 in the 2020 ECR https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202020.pdf

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

has been made this year in the modelling of smaller generators, particularly those with lower de-rating factors such as solar and short-duration storage – for these generators we split any aggregate capacity of this type into many smaller units (with a maximum size of 100 MW) so that their diversity is recognised. Other distributed technologies are also split into multiple blocks of capacity (e.g. by auction year and agreement length), which also contributes to the diversity of smaller generators.

While we have made these enhancements to our modelling inputs, the 2021 ECR modelling has used the same DDM version as in 2020, namely Release 6.1.28.1. We only change the DDM version when there is a development project carried out to assess the benefits and impact of moving to a new version.

2.7 National Grid ESO Analysis Delivery Timeline 2021

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 2020 and May 2021 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 2020
- Development projects phase October 2020 to February 2021
- Production plan developed in February 2021
- ECR modelling March to May 2021
- National Grid ESO's ECR sent to BEIS before 1 June 2021
- Publication of ECR in line with BEIS publishing auction parameters in July 2021

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. For details of the QA undertaken by National Grid ESO, see Annex A.9.

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

3. Scenarios & Sensitivities

3.1 Overview

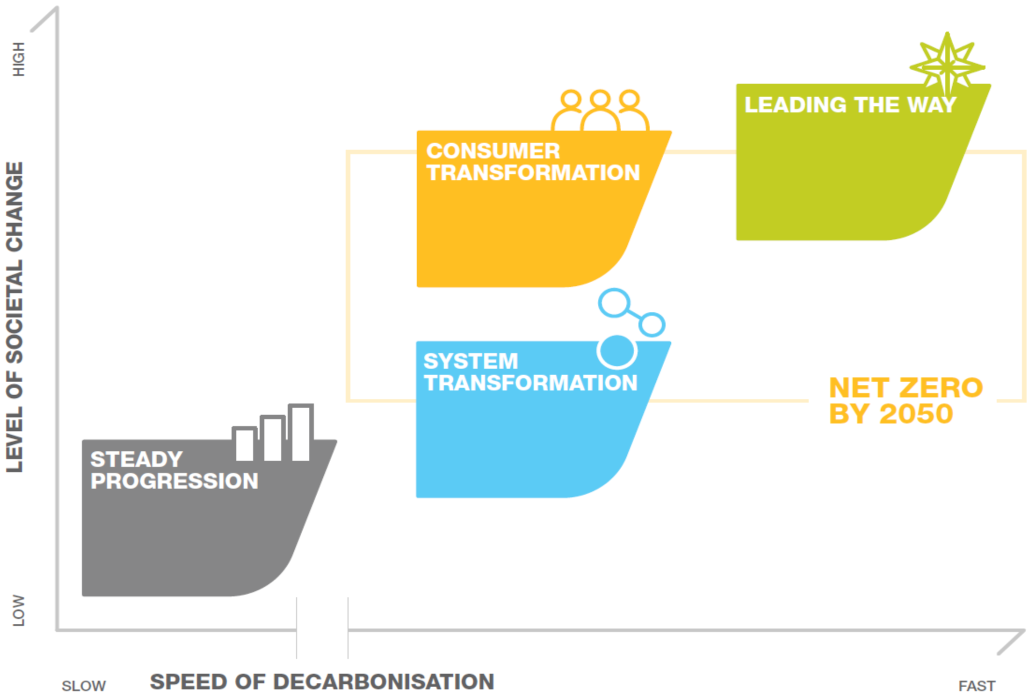
National Grid ESO has a well-established process to develop scenarios that reflect the uncertain supply and demand pathways on the future of energy in Great Britain. These scenarios are published annually in National Grid ESO's Future Energy Scenarios (FES) [26]. The scenarios consider the key challenges 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 an extensive stakeholder 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 2021, we engaged with over 450 different organisations, which is nearly twice as many as we did for FES 2020. The 2021 Stakeholder Feedback Document describes the key changes to this year's scenarios which are expected to be published in the FES 2021 document in the week commencing 12 July 2021. The FES 2021 scenario framework has been designed to explore the most fundamental drivers of uncertainty in the future energy landscape and is shown in Figure 6.

[26] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[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] https://www.nationalgrideso.com/document/187746/download

Figure 6: FES 2021 Scenario Framework



For FES 2021, we are retaining the same scenarios and framework as used in FES 2020, as we believe they are still fit for purpose, and our stakeholders tell us they value consistency from year to year. This means we have retained both the *speed of decarbonisation* axis and the *level of societal change* axis.

Of the few respondents to our consultation who didn't support the continuation of the 2020 framework, reasons ranged from the inclusion of Steady Progression being irresponsible to Leading the Way being over-optimistic. There was no clear trend in these responses to suggest a change for FES 2021 that would be supported across our stakeholders.

We have modelled four scenarios; three which meet or exceed the 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 continue to be met in all scenarios for FES 2021.

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, we have used a Base Case known as the 'Five-Year Forecast' to 2025/26, against which all the sensitivities will be run. This case follows the same principles and modelling approach as the main scenarios to give a five-year demand and generation background that represents our best view and is typically within the FES scenario range. Due to the inherent uncertainty across the market beyond 2025/26, we do not produce a forecast beyond the next five years. Instead, the Base Case follows the FES scenario that is closest in peak demand to provide a 15-year view in the ECR. In FES 2021, the Base Case is closest to the System Transformation scenario and so we have aligned the Base Case to this scenario from 2026/27 onwards in our ECR analysis.

The Base Case takes account of Capacity Market units awarded agreements in previous auctions that are now known not to be able to honour their contracts due to those agreements being terminated. Additional non-delivery may also be assumed in the Base Case based on our best view from market intelligence of capacity providers that are not currently expected to meet their obligations.

Energy demand

Demand reduction and decarbonisation continues at a steady pace due to economic, political and social focus elsewhere. In the Industrial & Commercial (I&C) sectors, the overall economic growth forecast used in the modelling is benchmarked to the latest November 2020 Office for Budget Responsibility report. The impact from COVID-19 reduces short term electricity demand. 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 continued acceleration in the growth of sales of battery electric cars and vans in 2020, broadly in line with expected projections in FES 2020. 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. We have updated our efficiency assumptions for electric vehicles to reflect recent changes in input data from the Department for Transport, leading to increased electricity demand for transport in all scenarios.

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. FES 2021 sees slower rollout of thermal insulation improvements relative to FES 2020, which leads to some increases in heating demand. Base Case assumptions 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 introduced a new spatial heat model that outputs results with greater granularity on a regional level[33]. The new model is intended to enhance our understanding of the potential decarbonisation routes, their likelihood, and the impact of these on networks as well as on consumers.

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[34] 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 five years. UK gas production and development is expected to follow recent trends.

3.2 Scenario Descriptions

The four FES scenarios for 2021 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.

[33] https://www.nationalgrideso.com/document/190471/download
[34] 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 the government's 2030 sales ban on internal combustion engine (ICE) cars, and 100% of new 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, the right conditions are not fully achieved to create the consumer confidence needed for the market to achieve the government's 2030 ban on petrol & diesel cars and vans. The bans for cars and vans are pushed back to 2032 and 2035 respectively. 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 plays a role to create negative emissions in the power sector to help 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 also sees a high level of hydrogen produced from reformation of biomethane with CCUS offering another source of negative emissions. 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, the government target to ban sales of petrol & diesel cars and vans by 2030 is met and we see 100% battery electric vehicle sales in 2030. We see increasing hydrogen demand for transport, particularly in heavy goods vehicles. Initial reluctance of HGV fleets to adopt Battery EVs, along with electrolysis making hydrogen widely available and cost competitive as a fuel, leads to significant uptake in hydrogen 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 and doesn't meet policy ambitions. Sales bans on non-zero emission petrol & diesel cars is pushed back to 2035, and vans to 2040, to protect UK car industry sales. Decarbonisation of other vehicles is slower still, with continued reliance on diesel for heavy goods vehicles. 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 less rigorous 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. Deployment of offshore wind has, however, increased in Steady Progression relative to FES 2020, reflecting the increased government commitment to the sector. The scenario relies more heavily on gas, particularly larger combined cycle gas turbines (CCGTs), for both generation and flexibility. It also includes some gas generation with CCUS this year, while FES 2020 had no CCUS in this scenario. 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 2025/26

The definition of peak demand used in the modelling is Unrestricted GB National Demand[35], 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[36] (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.

As the peak demand forecast used in the Capacity Market reflects total GB consumer demand (sometimes referred to as underlying demand), demand side response (DSR) including Triad avoidance is less relevant from demand perspective. While this is important in terms of how National Grid ESO operates the system since it reflects the demand on the transmission system, DSR and Triad avoidance is considered as supply in the CM since it participates in the auction.

There are four main demand areas that are modelled:

- Industrial & Commercial (excluding heat and transport)
- Residential (excluding heat and transport)
- Heat
- Road transport

Industrial and commercial demand is based on current views of energy policy and the latest ‘Oxford Economics’ baseline economic and price forecasts at the time of scenario creation. Residential demand comprises the other component of peak and takes into account energy policy, consumer behaviour and uptake of new technologies such as LED lighting and heat pump white goods. Heat is based on a new model which considers location, housing types, thermal efficiency, energy policy, technology types and consumer adoption rates. Road transport considers energy policy, efficiency, consumer choice and uptake rates.

The starting point for our demand forecast projections is the out-turn for the most recent winter. However, the impact of the COVID-19 lockdown means that we are unable to reliably establish the out-turn for winter 2020/21 using the established ACS methodology Therefore, we have assumed our previous Base Case forecast in FES 2020 for winter 2020/21 as our starting point. Even if we were able to establish a reliable out-turn for winter

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

2020/21, we do not expect this to have a significant impact on forecasting future years, since we are not expecting future winters to have a demand suppression due to COVID-19 lockdown (i.e. winter 2020/21 is the only winter we expect a COVID-19 lockdown for, and is therefore an outlier in the time series).

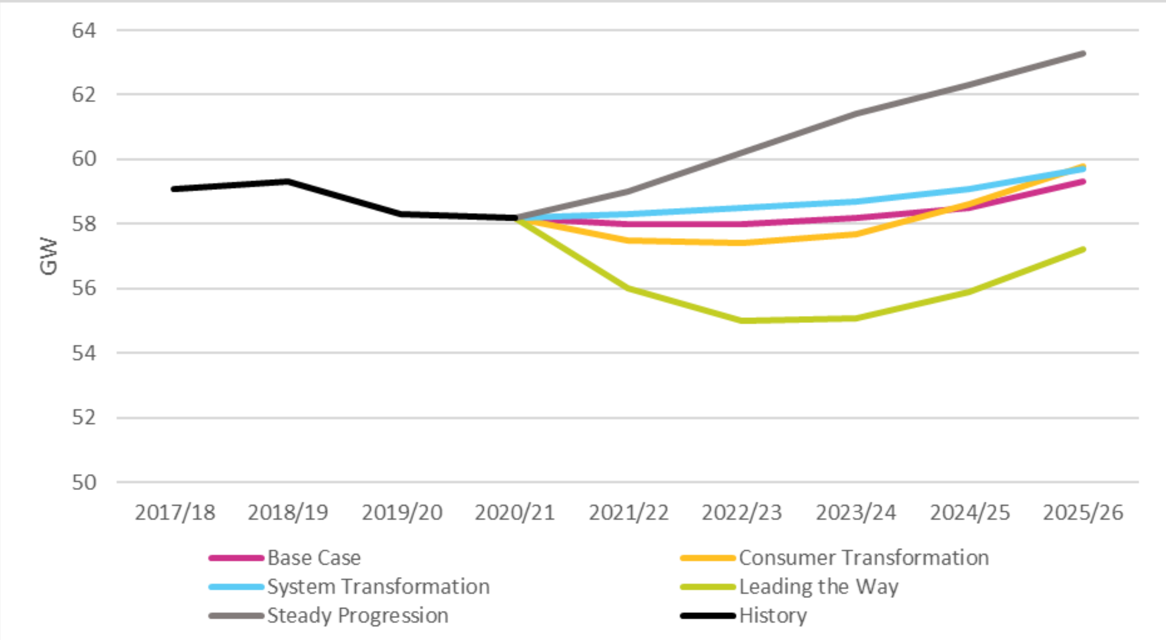
We carried out additional analysis last year to assess the potential impact of COVID-19 on the demand forecast assumptions used in the 2020 ECR. This assessment showed a potential reduction in peak demand of 3 – 12% depending on the duration of the pandemic and speed of recovery[37]. Based on our observations from winter 2020/21, we estimate that the peak demand suppression due to the COVID-19 pandemic on the coldest days may not have been as high. We have therefore revised our peak demand forecasts in the Base Case and FES 2021 such that we assume there is no peak demand suppression due to COVID-19 from winter 2021/22 onwards.

The main elements driving the 1.8 GW change in underlying demand by 2025/26 are:

- Industrial and commercial demand is 1.1 GW higher by 2025/26.
    - Increase is mainly due to lower energy efficiency.
- The electrification of transport and heat is 0.7 GW higher by 2025/26.
    - Evidence of greater Electric Vehicle sales and lower vehicle efficiency.
    - Greater Heat Pump demand.
    - Lower thermal efficiency than previously forecast.

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 2017/18.

Figure 7: Peak Demand - FES Scenarios and Base Case to 2025/26



[37] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/FES%2020%20Covid-19%20Update%20-%20February%202021%20V1.pdf

Table 6: Peak Demand to 2025/26

Peak Demand GW	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Base Case	58.2	58.0	58.0	58.2	58.5	59.3
Consumer Transformation	58.2	57.5	57.4	57.7	58.6	59.8
System Transformation	58.2	58.3	58.5	58.7	59.1	59.7
Leading the Way	58.2	56.0	55.0	55.1	55.9	57.2
Steady Progression	58.2	59.0	60.2	61.4	62.3	63.3

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 2021 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.

Compared to FES 2020, the FES 2021 assumptions incorporate less efficiency (industrial processes, building thermal insulation and electric vehicle efficiency) built into the demand, which affects all scenarios. The following narrative compares the 2020 scenarios against those used last year.

The efficiency assumptions for electric cars have been updated to recognise decreased efficiency in data published[38] by the Department for Transport. The updated data aligns well with other industry and government publications. This efficiency decrease has resulted in an increase of energy usage of about 30% for cars. The government's legislation, bringing forward the ban on petrol and diesel cars, has also led to an increase in energy usage for electric vehicles.

The assumptions for fuel switching and energy efficiency have been updated. This is based on an updated methodology to better reflect the real-world efficiency savings in combination with fuel-switching. This has had the effect of increasing the electricity demand relative to FES 2020.

The assumptions for building thermal efficiency have also been updated this year. This reflects feedback from FES 2020 stakeholders and is more aligned to the assumptions used by the Climate Change Committee (CCC). The lower thermal efficiency within the modelling has had the effect of increasing the electricity demand for FES 2021.

3.4 Demand Forecast 2026/27 onwards

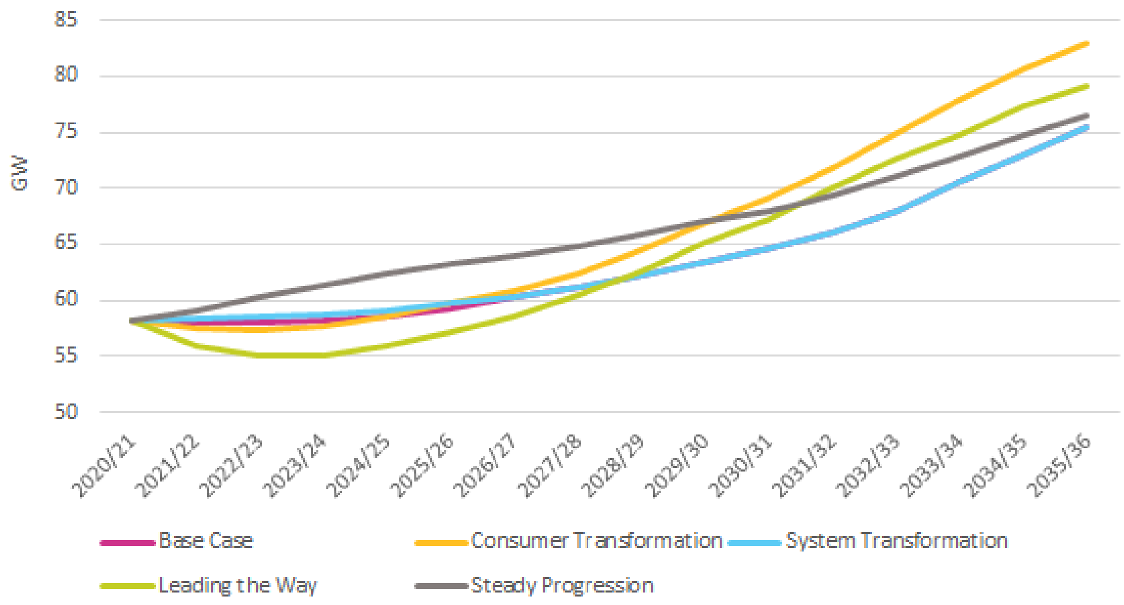
Demand is expected to increase due to adoption of electrified road transport and electrified, low carbon heat. Key uncertainties are the levels of 'smart' energy use to reduce system peak (particularly from electric vehicle charging and heat storage) and the speed of adoption.

[38] https://www.gov.uk/government/publications/tag-data-book

Electricity demand continues to increase, even more so than in FES 2020, largely due to the changes in efficiency described for the period up to 2025/26. Please refer to Annex A.1 for details on the demand assumptions used in the FES scenarios.

Figure 8 shows the peak demands used in the DDM modelling to 2035/36.

Figure 8: Peak Demand - FES Scenarios and Base Case to 2035/36



3.5 Generation Capacity until 2025/26

Our generation capacity assumptions from 2020/21 to 2025/26 are based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years.

The Base Case for transmission capacity sits within the uncertainty envelope provided by the 2021 FES as shown in Figure 9 and Table 7[39].

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

Figure 9: FES 2021 Transmission connected nameplate capacity to 2025/26

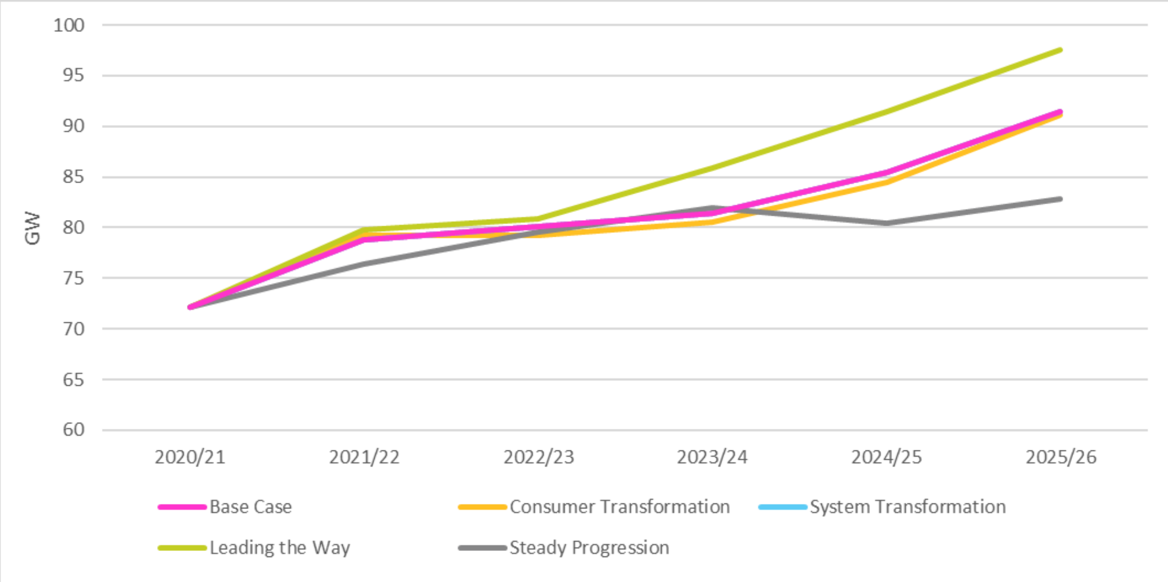


Table 7: Transmission connected nameplate capacity (GW) to 2025/26

Capacity (GW)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Base Case	72.1	78.8	80.1	81.4	85.5	91.5
Consumer Transformation	72.1	79.3	79.3	80.5	84.4	91.2
System Transformation	72.1	78.8	80.1	81.4	85.5	91.5
Leading the Way	72.1	79.7	80.9	85.9	91.4	97.5
Steady Progression	72.1	76.4	79.5	81.9	80.4	82.9

We assume that the price of the new UK Emissions Trading Scheme (ETS) will be similar to the EU ETS and that the two will continue on a similar trajectory out to 2050. The GB Carbon Price Support is assumed to continue in line with Budget announcements before gradually being phased out as the ETS increases.

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 Department for the Environment, Food and Rural Affairs (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 conditions.

3.6 Generation Capacity 2026/27 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. The data in this section was taken from a near final version of the FES. Since then, the FES generation assumption from 2026/27 onwards have been revised slightly.

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).

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 0.4 to 0.5 GW over the period to 2025/26 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

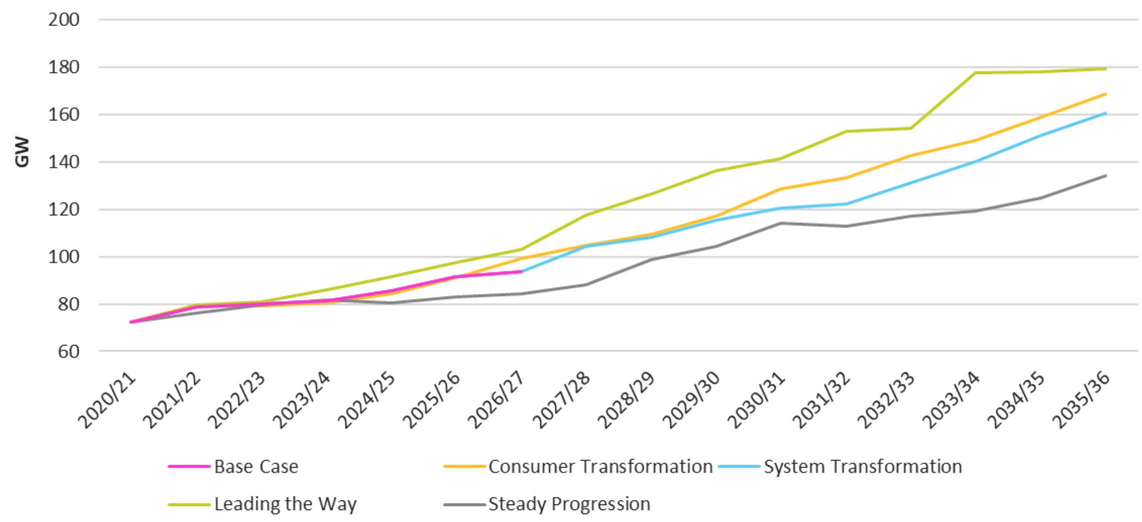
Barring these exceptions based on size and support mechanism, all other forms of generation capacity are eligible for the Capacity Market. For the purposes of our modelling, we assume that:

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

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 2021 transmission connected nameplate capacity to 2035/36



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 2021 document is published in week commencing 12 July 2021[40].

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 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[41].

A variety of data sources[42] 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.

Figure 11 and Table 8 show nameplate capacities (excluding solar) for distributed generation out to 2025/26. Figure 12 extends the capacities out to 2035/36.

[40] The ECR 2021 modelling was carried out using the FES assumptions that were provided on 20 April 2021. Since then some small changes have been made, particularly to assumptions in later years, which do not impact our recommendations. However, this may result in an apparent discrepancy between the FES data included in the 2021 ECR and that published in FES 2021 (available July 2021)
[41] The de-rating factor for solar is less than 4% for CM auctions
[42] For example, Renewable Energy Planning Database, CM register, DNO long term development statement and others

Figure 11: Distributed generation nameplate capacity (excl. solar) to 2025/26

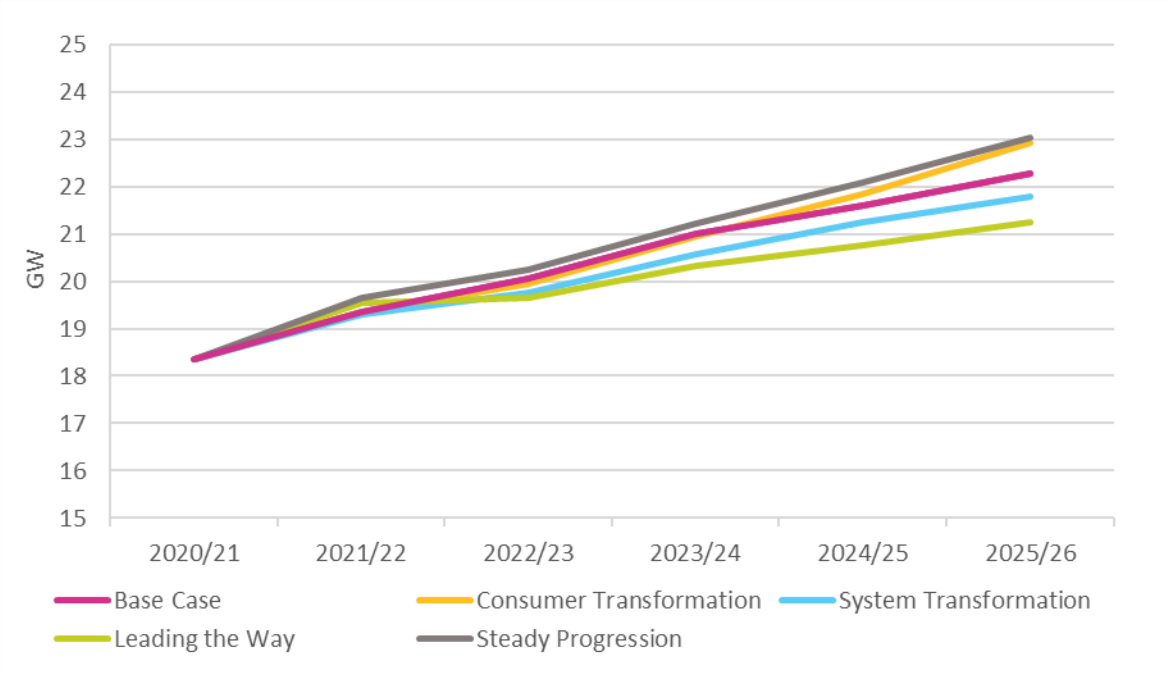
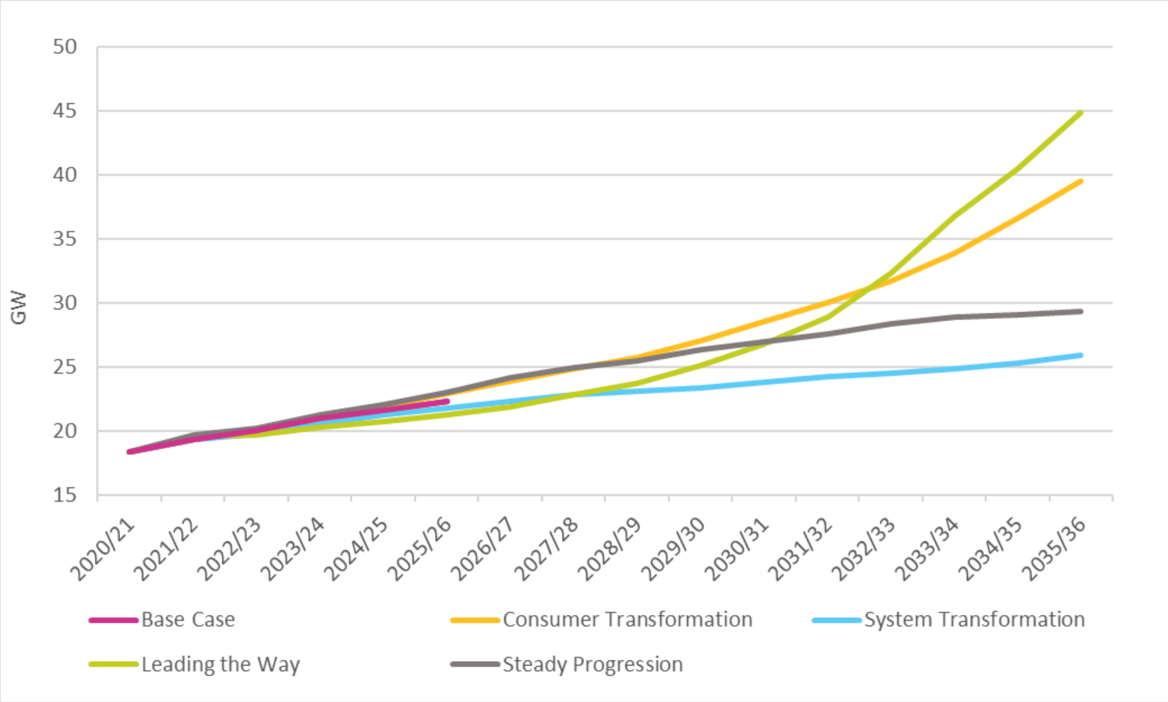


Table 8: Distributed generation nameplate capacity (excluding solar) (GW)[43]

Capacity (GW)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Base Case	18.3	19.4	20.1	21.0	21.6	22.3
Consumer Transformation	18.3	19.4	20.0	21.0	21.8	22.9
System Transformation	18.3	19.3	19.8	20.6	21.3	21.8
Leading the Way	18.3	19.6	19.7	20.3	20.8	21.2
Steady Progression	18.3	19.6	20.2	21.2	22.1	23.0

[43] Includes capacity <1 MW

Figure 12: Distributed Generation (excluding solar) to 2035/36 (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.

Observed Triad avoidance in winter 2019/20 was 2.4 GW. In winter 2020/21, this reduced to 1.3 GW. It is believed this is a market response to changes in the charging regime, which has changed the value of generating at the time of transmission peak demand.

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 (TOUTs), 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 TOUTs incentivises consumers to move those energy demanding activities to off peak times where possible. The more engaged consumers, energy suppliers and government are, the greater the impact of TOUTs.

Industrial and Commercial 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.

The chart in Figure 13 shows the industrial and commercial DSR for the scenarios to 2035/36, with Table 9 showing projections to 2025/26 and spot years for 2030/31 and 2035/36. 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[44] demand for 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. This results in low demand relative to other scenarios. As demands are lower when comparing with other scenarios, 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 FES 2020. 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 similar levels of DSR to Leading the Way. Leading the Way is 0.7 GW higher than FES 2020 levels, reflecting the increased peak demand. Leading the Way has relatively high levels of DSR as this scenario reflects a rapid drive to as efficient and smart system as possible.

The range of DSR by 2035/36 is 2.1 GW - 7.4 GW, which overlaps and exceeds the FES 2020 range of 1.6 GW - 6.8 GW by 2034/35 modelled in 2020. This reflects the increased demands forecast in FES 2021.

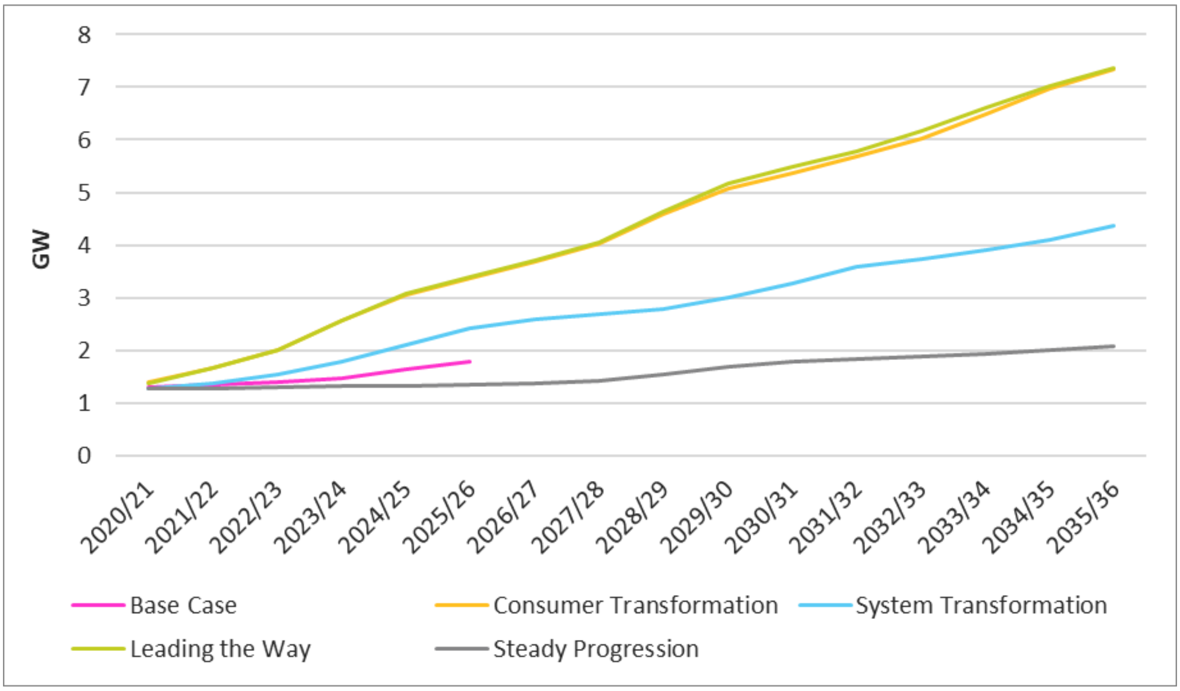
We acknowledge that in the CM auctions, successful unproven DSR aggregators may contract with behind the meter generation as well as demand side response providers to fulfil their CM obligations.

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

Table 9: Industrial and Commercial DSR (GW)

I&C DSR (GW)	2021/22	2022/23	2023/24	2024/25	2025/26	2030/31	2035/36
Base Case	1.3	1.4	1.5	1.6	1.8		
Consumer Transformation	1.7	2.0	2.6	3.1	3.4	5.4	7.3
System Transformation	1.4	1.5	1.8	2.1	2.4	3.3	4.4
Leading the Way	1.7	2.0	2.6	3.1	3.4	5.5	7.4
Steady Progression	1.3	1.3	1.3	1.3	1.3	1.8	2.1

Figure 13: Industrial and Commercial DSR to 2035/36



Power Responsive

Power Responsive[45] is a stakeholder-led programme facilitated by National Grid ESO, to stimulate increased participation in the different forms of flexible technology such as DSR, small scale generation and energy storage.

The programme brings the demand side flexibility (DSF) industry and energy users together to work in a co-ordinated way.

A key priority is to grow participation in DSF, by making it easier for industrial and commercial businesses to get involved and realise the financial and carbon cutting benefits of participating in the energy flexibility industry.

The role of Power Responsive is to:

- Raise awareness of DSR and engage effectively with businesses.
- Shape the growth of the market in a joined-up way and ensure demand has equal opportunity with the supply side when it comes to balancing the system.

[45] http://powerresponsive.com/

Power Responsive is overseen by a high-level steering group, composed of representatives from government, the regulator, system operators, and various industry players.

3.9 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects. We have anonymised the data by showing only the total capacity per year, due to commercial sensitivities. We assume that the total GB carbon price continues on a similar trajectory to the EU Emissions Trading Scheme. The GB carbon price support is also assumed to continue in the near future. However, we have assumed that the current political uncertainty means that there are no new interconnectors in our Base Case by 2025/26 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, the European Commission and the project developers themselves. 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 all scenarios, we assumed that the supply chain has enough capacity to deliver all interconnector projects.

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 followed by Consumer Transformation, System Transformation and lastly Steady Progression. The Base case has been aligned to System Transformation.

Table 10: Import Capacity Levels for Interconnection (GW)

Capacity (GW)	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2030/31
Base Case	4.75	5.66	8.4	9.8	9.8	9.8	15.9
Consumer Transformation	4.75	7.06	8.4	9.8	9.8	9.8	18.65
System Transformation	4.75	5.66	8.4	9.8	9.8	9.8	15.9
Leading the Way	4.75	7.06	8.4	9.8	9.8	13.1	21.55
Steady Progression	4.75	5.66	7.4	8.4	9.8	9.8	15.9

3.10 Sensitivities

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 weather, station availability, peak demand[46] and over/non-delivery. 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.

3.10.1 Weather

This sensitivity covers the potential uncertainty due to weather that may occur in a particular winter. The LOLE calculation in the DDM uses a relatively short weather history of just 13 years and so we cannot be confident that this will be representative of future years. This sensitivity is therefore justified as the statistical uncertainty associated with colder and / or warmer winters may not be fully reflected.

In the 2021 ECR, we have changed how we model the sensitivities to assess the impact of weather uncertainty. The new approach effectively combines the cold / warm winter and wind sensitivities that we have modelled previously in the ECR. The cold winter sensitivity is modelled using the demand and wind from winter 2010/11 only. The warm winter sensitivity is modelled using the demand and wind from winter 2006/07 only. This approach also means that we better reflect any potential correlation between wind and temperatures.

These years are chosen because they represent the years that will have the highest and lowest requirements to meet 3 hours LOLE, respectively within our 13-year history. These winters do not represent best or worst-case scenarios as our relatively short history will not cover all potential weather scenarios. We have been supporting a project led by the National Infrastructure and Met Office to develop data sets to assess the impact of credible, extreme weather scenarios that have not happened before.[47] We are intending to explore and assess use of this data in a development project for the 2022 ECR.

This is the only change in how this sensitivity is modelled. Our modelling continues to assume the output from wind generation is lower at times of peak demand based on previous research supported by our academic consultants[48]. 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.

[46] 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
[47] https://nic.org.uk/studies-reports/national-infrastructure-assessment/characterising-adverse-weather-uk-electricity-system/
[48] For example, see section 2.5 in the 2019 ECR for further information.

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 seven years. However, as this is a relatively small sample size, there is an associated uncertainty of the mean value and the subsequent distribution of conventional generation used in the LOLE calculation. This sensitivity is justified as the small sample size means we cannot be confident that the mean values will be statistically representative of what could happen in future.

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 2022/23 T-1 auction. There is no material impact on the analysis for the 2025/26 T-4 auction as only a small amount of capacity has already been secured for that year.

We have proposed changes to the high / low availability sensitivities compared with how we have modelled it previously in the ECR based on recent performance of the thermal fleet. Annex A.4.4 shows how the availability for CCGT, nuclear, coal and biomass has changed over the last seven years.

In the 2021 ECR, the high availability is only applied to CCGTs rather than CCGTs and nuclear. We believe the removal of nuclear from this sensitivity is justified as the nuclear fleet is approaching the end of its life and the availability of the fleet has not approached such levels in the last five winters.

The low availability is now applied to CCGTs, nuclear and coal rather than just CCGTs and nuclear. We believe the additional inclusion of coal in this sensitivity is justified based on the availability of coal in winter 2020/21 that led to an adjustment for the 2021/22 T-1 auction target. Given we may only have one operational coal station in 2022/23, we have assumed a coal availability of 50% in this sensitivity.

We use a value of one standard deviation below the mean for the low availability values. A statistical argument could be made as to whether this is appropriate for nuclear given that the data in Annex A.4.4 appears to show a downward trend rather than scatter around a mean value. However, we estimate that possible alternatives such as a 3-year average or extrapolating a linear trend would not have a material impact on our recommendation. The difference between using a 3-year average is only around 1%. There is also significant uncertainty on extrapolating a linear trend as we currently expect at least two stations to close by 2022/23. The closure of the oldest stations could potentially see the availability of the remaining fleet increase. On this basis, we have continued to use a value of one standard deviation below the mean for the nuclear low availability in this sensitivity. Table 11 shows the current values used for the high and low availability sensitivities in this year's modelling.

As this sensitivity addresses uncertainty in the distribution of conventional generation used in the LOLE calculation, we do not include interconnectors. In the DDM, we model interconnectors using a separate distribution dependent on GB system margin as described in Section 2.4.2. We believe it is more appropriate to consider the uncertainty around interconnectors in the over- and non-delivery sensitivities.

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

Technology	Low availability	High availability
CCGT	88%	93%
Nuclear	74%	N/A
Coal	50%	N/A

3.10.3 High / Low Demand

This sensitivity covers the uncertainty associated in forecasting the average cold spell (ACS) peak demand. The sensitivity is modelled based on a range of ± 2% around the Base Case peak demand. This is consistent with the range for National Grid ESO's Demand Forecast Accuracy (DFA) incentive. This is unchanged since the 2020 ECR.

It is worth noting that the peak demand forecasts in the FES show a much wider range than this (see Section 3.3). Therefore, it may be reasonably argued that the uncertainty is already covered by the FES (e.g. the scenarios have different assumptions on key demand drivers such as energy efficiency, electric vehicles, consumer behaviour and heating) This sensitivity was originally introduced when the FES peak demand range was much narrower. Should the FES continue to have a wide range of peak demands in future, we may decide that this sensitivity is no longer required, and we will review this in the 2022 ECR.

3.10.4 Non-delivery

This sensitivity covers the risk that capacity providers are unable to deliver in line with their capacity market agreements – their de-rating factor is effectively zero. (e.g. a station with an agreement closes before the delivery year, a station is offline for the whole of the winter, or a new station is delayed). The sensitivity reflects risk of non-delivery that we don't know about yet. This contrasts to non-delivery that we include in our Base Case assumptions. Non-delivery in our Base Case reflects capacity that we either already know or do not expect to meet its existing Capacity Market agreement based on our market intelligence (e.g. providers who have terminated their agreements would fall into the former category). Non-delivery in the Base Case has a direct impact on the target capacity since if we assume 1 GW non-delivery in the Base Case, this will increase the auction target capacity by 1 GW. Non-delivery in the Base Case, including terminations, are highlighted in Chapters 5 and 6. Non-delivery sensitivities impact the target capacity through their inclusion in the Least Worst Regret calculation (e.g. if we include sensitivities with higher non-delivery, then this increases the possibility of a higher recommendation).

Since the 2018 ECR, we have modelled the non-delivery sensitivities by considering different sources of non-delivery combined using a root sum of squares approach with subsequent calculation of market response. This determines the maximum level of non-delivery. Non-delivery sensitivities were then modelled in steps of 0.4 GW up to this maximum level. This approach typically led to a maximum non-delivery sensitivity of 2.4 - 2.8 GW.

In winter 2020/21, we estimate that observed non-delivery during the coldest part of the winter (early December to early February) exceeded 5 GW. This represents capacity that was unavailable for the entire period (i.e. essentially a de-rating factor of zero) rather than capacity that was available but under-performed against its de-rating factor[49]. This capacity did not transfer its agreements via secondary trading. This capacity may be subject to penalties and/or termination depending on whether it has demonstrated requirements set out in the Capacity Market Rules. While most of the non-delivery became apparent ahead of the winter, and was reflected in our 2020/21 Winter Outlook assessment, it was not known ahead of the T-1 auction for 2020/21 that took place in February 2020 – our last opportunity to secure capacity for the winter. This capacity represented some large CCGTs that were unavailable for the period; two nuclear power stations on long-term outage; new-build distributed generation that was delayed in connecting ahead of winter 2020/21 and is now potentially at risk of termination; an interconnector cable outage.

In January 2021, we carried out our adjustment to the demand curve to provide our final recommendation for the T-1 auction for delivery in 2021/22. At the time of making this adjustment, we expected non-delivery for 2021/22 to also exceed 5 GW. This was reflected in our adjustment and contributed to the higher auction target[50].

Our observations of non-delivery in winter 2020/21 and our assessment of non-delivery in January 2021 for winter 2021/22 are both significantly higher than levels of non-delivery assumed in our modelling (i.e. our experience of non-delivery exceeds 5 GW, but the maximum level included in the modelling is just 2.4 – 2.8 GW). Table 12 sets out this comparison.

Table 12: Comparison of non-delivery assumptions used in our modelling in the 2019 ECR with observations for winter 2020/21 and expected non-delivery for winter 2021/22 (as of Jan 2021)

Category	2020/21 modelled non-delivery (GW)[51]	2020/21 modelled root sum of squares (GW)	2020/21 observed non-delivery (GW)	2021/22 expected non-delivery as of Jan 2021 (GW)[52]
Large thermal	3.0	9.0	2.4	2.0
Nuclear	0	0	1.8	2.7
Distributed generation	1.3	1.7	0.5	0.5
Unproven DSR	0.3	0.1	Unknown	Unknown
Interconnectors	0.7	0.5	0.9	0.7
Sum of non-delivery	**5.3**	**3.4**	**5.6**	**5.9**
Potential market response	-1.3	-0.8	-0.5 (estimate)	-1.0 (estimate)
Total	**4.1**	**2.4** (rounded to nearest 0.4)	**5.1**	**4.9**

[49] Details on the adjustment to the demand curve including non-delivery can be found here: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Report%20to%20Secretary%20of%20State%20regarding%20update%20to%20Demand%20Curve%20T-1%202021-22.pdf. We should highlight that we don't consider coal as non-delivery for winter 2020/21. The fleet was available, but its availability was lower than expected based on its de-rating factor (see Section 4.1)

[50] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Report%20to%20Secretary%20of%20State%20regarding%20update%20to%20Demand%20Curve%20T-1%202021-22.pdf

[51] The 2019 ECR describes the maximum non-delivery sensitivity of 2.4 GW in section 3.10.10. Table 12 in this report provides additional detail showing how we arrived at the maximum value of 2.4 GW in the 2019 ECR. The additional details in Table 12 showing how we arrived at the 2.4 GW total were previously unpublished. Link to 2019 ECR: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

[52] This was based on market intelligence at the time when we carried out our Adjustment to the Demand Curve in January 2021. See the report in footnote reference 49 for more information.

These observations naturally lead to questions as to why non-delivery was so high in winter 2020/21 and whether the modelling assumptions are reflecting the risk appropriately. There appear to be different reasons behind the non-delivery observed in winter 2020/21. Some elements of non-delivery may have been driven by economic reasons, but there was a significant amount that does not appear to be driven by economics. For example, nuclear non-delivery in recent years has been due to prolonged outages and stations approaching end of life, which relates to safety compliance and requires approval of safety cases; interconnector non-delivery has been due to technical reliability of the equipment; and non-delivery from smaller distributed generation in winter 2020/21 was due to delays in building new capacity. While the various types of non-delivery appear to be unrelated, we should not rule out that there may be a common driver.

Our modelling on non-delivery was informed by a development project undertaken in 2017/18 and reported in the 2018 ECR. The analysis considered different categories of non-delivery along with a market response. For example, non-delivery from large thermal plant was largely driven by profitability and considered that there might be an economic interaction between stations (e.g. suppose a power station was to shut earlier than expected, then the non-delivery from this station could mean another uneconomic station can generate more and become profitable such that it remains open). However, other types of non-delivery may have different drivers and therefore be unrelated. The different categories of non-delivery were therefore combined using a root sum of squares approach – reflecting that we would not expect all these non-delivery events to occur simultaneously.

For now though, we have proposed to change our approach in how the non-delivery sensitivities are constructed in the 2021 ECR. One of the observations from Table 12 is that the modelling assumptions for non-delivery are closer to what we observed when we do not combine the different types using the root sum of squares approach. Therefore, we have proposed to model non-delivery as the sum of the discrete components with an allowance for market response in the 2021 ECR. It may be that we return to the root sum of squares approach (or some other approach) in future. There is clearly a need to better understand the drivers behind non-delivery, such that non-delivery risks are (a) modelled appropriately and (b) minimised to reduce consumer costs. This is work that will need to be taken forward ahead of the 2022 ECR.

Table 13 and Table 14 show our non-delivery assumptions for the 2021 ECR, which sets out the different types of non-delivery and potential market response. The impact of these changes means that we have included non-delivery sensitivities up to 5.2 GW and 5.6 GW for the T-1 for delivery in 2022/23 and T-4 for 2025/26 auctions, respectively. The root sum of squares approach is shown for comparison. Further detail on these assumptions is provided in Annex A.5.1.

Table 13: Maximum non-delivery for the T-1 auction for 2022/23 was assumed to be 5.2 GW

Category	Non-delivery (GW)	Root sum of squares (GW)
Large thermal	2.5	6.3
Nuclear	1.8	3.2
Distributed generation	0.7	0.5
Unproven DSR	0.4	0.2
Interconnectors	1.4	2.0
Sum of non-delivery	**6.8**	**3.5**
Potential market response	-1.5	-0.8
Total	**5.2** **(rounded to nearest 0.4)**	**2.7**

Table 14: Maximum non-delivery for the T-4 auction for 2025/2026 was assumed to be 5.6 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	2.5	6.3
Sum of non-delivery	**7.4**	**3.8**
Potential market response	-1.6	-0.8
Total	**5.6** (rounded to nearest 0.4)	**2.9**

We recognise that changing our modelling approach for non-delivery (and over-delivery as set out in Section 3.10.5) may have an impact on the Least Worst Regret calculation and our recommendation on the target capacity. There is clearly uncertainty in the non-delivery (and over-delivery) assumptions. We have therefore assessed how robust the outcome of the Least Worst Regret calculation is when considering different levels of maximum non-delivery in Sections 5.3.4 and 6.3.4, respectively.

3.10.5 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 reflects over-delivery above what we may have assumed in the Base Case. Over-delivery assumed in the Base Case has a direct impact on the target capacity, while over-delivery sensitivities impact the target capacity through the Least Worst Regret calculation.

While we currently treat non-delivery and over-delivery sensitivities separately, they can in essence be considered as a continuum of *net delivery* with categories of over / non-delivery and associated market response. On this basis, we therefore think it appropriate that we use a consistent approach for the over- and non-delivery sensitivities. This means that we have not combined the categories of over-delivery using a root sum of squares approach either. Table 15 and Table 16 show the over-delivery assumptions for the 2022/23 T-1 and 2025/26 T-4 auctions, respectively. Further details on these assumptions are provided in Annex A5.1.

Table 15: Maximum over-delivery for the T-1 auction for 2022/23 was assumed to be 3.2 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	1.3	1.7
Sum of non-delivery	**4.1**	**2.2**
Potential market response	-0.9	-0.5
Total	**3.2**	**1.8**

Table 16: Maximum over-delivery for the T-4 auction for 2025/26 was assumed to be 4.0 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	2.2	4.8
Sum of non-delivery	**5.0**	**2.9**
Potential market response	-1.2	-0.7
Total	**4.0** (rounded to nearest 0.4)	**2.2**

3.10.6 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.

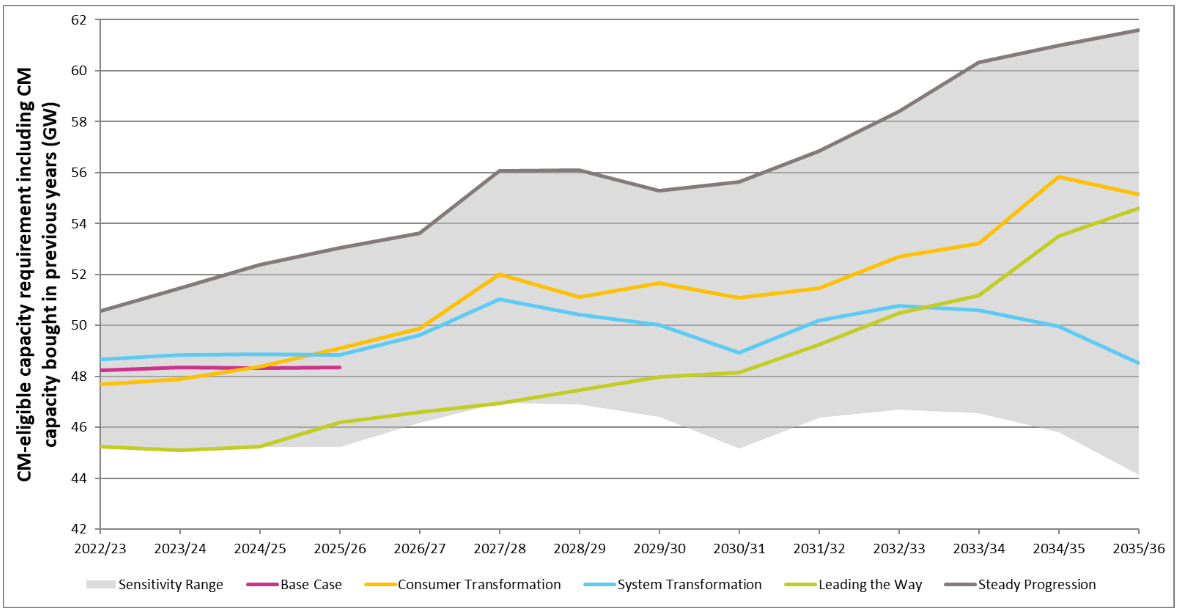
3.11 15-Year Horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2022/23 and 2025/26). 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 2022/23, 2024/25 and 2025/26 was derived from the 2022/23 model runs (see Chapter 5) and the capacity requirement from 2026/27 to 2035/36[53] from the model runs for 2025/26 (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.

[53] This chart was based on data taken from a near final version of the FES. Since then, the FES generation assumption from 2026/27 onwards have been revised slightly

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. The total requirements for sensitivities generally fall within the scenario range, particularly in the early years. However, in the later years, the low demand and warm winter sensitivities fall outside of the scenario range and the bottom of the range is set by the Base Case warm winter sensitivity in those years.

As can be seen in Figure 14, the Consumer Transformation, Steady Progression and Leading the Way scenarios show an increased requirement in general over the period, driven largely by an increase in peak demand. For the System Transformation scenario, 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, 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 and there is a consultation[54] on bringing this forward to 2024. 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.

[54] https://www.gov.uk/government/consultations/early-phase-out-of-unabated-coal-generation-in-great-britain

The capacity already secured for each year over the 15-year period can be obtained by looking in the CM registers and is summarised in the table and chart on page 5 of the final results report for the 2024/25 T-4 auction[55]. Note that the values in the 2024/25 T-4 auction results report may not include recent terminations and may differ from the values calculated by the DDM. Reasons for this include 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. Table 55 in Annex A.8 contains a summary of total capacity secured in each auction to-date.

Figure 14 shows the level of CM capacity required to meet the Reliability Standard in all years from 2022/23. For 2021/22, 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 2021/22 Winter Outlook Report[56] will include a view of electricity security of supply for the coming winter.

[55] See page 85 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20T4%20DY2024-25%20Final%20Report.pdf
[56] 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 17, 18 and 19 show the de-rating factors for conventional plants, storage and renewables, respectively. The de-rating factors cover both 2022/23 T-1 and 2025/26 T-4 auctions. Previous de-rating factors from the 2020 ECR are also shown in the table for comparison. No changes have been made to the methodology used to determine these de-rating factors since last year.

Conventional plant de-rating factors are calculated annually using the availability of transmission-connected generation during the winter peak period over the last seven years. Further detail behind these assumptions is provided in Annex A.4.4. While we have not made any changes to the methodology, we have now recommended separate de-rating factors for coal and biomass. Previously, we used the same de-rating factor for these technologies. This was justified on the basis that the biomass stations were predominantly coal conversions (so similar technology) and that we didn't have a full seven-year history due to the conversions being relatively recent. Furthermore, the relative capacities of coal and biomass meant that the de-rating factor was weighted significantly toward coal, which has been more dominant in the Capacity Market than biomass. We have now reached a point where it is more appropriate to provide separate de-rating factors. This is justified on the basis that we now have a reasonable history to assess the availability of biomass conversions independently. In addition, coal closures have resulted in biomass representing over 40% of the combined capacity. Coal availability dropped to just 61% in winter 2020/21 and with closures imminent in the next few years, plant operators may be reluctant to continue to invest in these stations.

Storage de-rating factors apply to plant types that include: 'conversion of imported electricity into a form of energy that 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[57]. 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.

This year, there is a lower level of storage capacity in the 2021 ECR Base Case than in the 2020 ECR Base Case in the T-1 year (even though the years have advanced by one) and a higher level in the T- 4 year (see Annex A.6 for more details). As a result, the duration threshold corresponding to 95% of stress events has reduced from 5 hours to 4.5 hours in the T-1 year and increased from 5 hours to 5.5 hours in the T-4 year, resulting in step changes in the de-rating factors for these durations in those years in Table 18.

Renewable de-rating factors are based on the methodology[58] that was consulted with the industry in February 2019.

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

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

Table 17: De-rating factors for conventional plants and DSR

Technology Class	Plant Types Included	ECR 2020	ECR 2021*
Oil-fired steam generators	Conventional steam generators using fuel oil	95.22%	95.47%
Open Cycle Gas Turbine (OCGT)	Gas turbines running in open cycle fired mode	95.22%	95.47%
Reciprocating engines (non-autogen)	Reciprocating engines not used for autogeneration	95.22%	95.47%
Nuclear	Nuclear plants generating electricity	81.43%	80.44%
Hydro (excl. tidal / waves)	Generating Units driven by water, other than such units: a) driven by tidal flows, waves, ocean currents or geothermal sources; or b) which form part of a Storage Facility	90.99%	91.15%
CCGT	Combined Cycle Gas Turbine plants	90.00%	90.92%
CHP and autogen	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%	90.92%
Coal	Conventional steam generators using coal	84.80%	80.11%
Biomass	Conventional steam generators using biomass	84.80%	88.55%
Energy from Waste	Generation of energy from waste, including generation of energy from: a) conventional steam generators using waste; b) anaerobic digestion; c) pyrolysis; and d) gasification.	84.80%	88.55%
DSR[59]		79.21%	78.45%

* De-rating factors apply to both the 2022/23 T-1 and 2025/26 T-4 auctions.

Table 18: De-rating factors for duration limited storage

<table>
<tr><th>Duration (hours)</th><th>ECR 2020
2021/22 T-1</th><th>ECR 2020
2024/25 T-4</th><th>ECR 2021
2022/23 T-1</th><th>ECR 2021
2025/26 T-4</th></tr>
<tr><td>0.5</td><td>12.75%</td><td>12.38%</td><td>12.94%</td><td>9.98%</td></tr>
<tr><td>1.0</td><td>25.32%</td><td>24.77%</td><td>25.87%</td><td>19.96%</td></tr>
<tr><td>1.5</td><td>37.71%</td><td>36.97%</td><td>38.62%</td><td>29.94%</td></tr>
<tr><td>2.0</td><td>49.17%</td><td>48.62%</td><td>50.63%</td><td>39.73%</td></tr>
<tr><td>2.5</td><td>58.23%</td><td>58.78%</td><td>60.61%</td><td>48.97%</td></tr>
<tr><td>3.0</td><td>64.70%</td><td>66.18%</td><td>67.82%</td><td>56.18%</td></tr>
<tr><td>3.5</td><td>68.76%</td><td>70.98%</td><td>72.25%</td><td>61.54%</td></tr>
<tr><td>4.0</td><td>71.35%</td><td>73.76%</td><td>74.84%</td><td>64.86%</td></tr>
<tr><td>4.5</td><td>73.20%</td><td>75.79%</td><td rowspan="3">94.61%</td><td>67.45%</td></tr>
<tr><td>5.0</td><td rowspan="2">94.64%</td><td rowspan="2">94.64%</td><td>69.48%</td></tr>
<tr><td>5.5+</td><td>94.61%</td></tr>
</table>

59 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 19: De-rating factors for renewables

Technology Class	ECR 2020 2021/22 T-1	ECR 2020 2024/25 T-4	ECR 2021 2022/23 T-1	ECR 2021 2025/26 T-4
Onshore Wind	8.01%	7.81%	7.81%	6.25%
Offshore Wind	12.11%	11.13%	11.33%	8.59%
Solar PV	2.54%	2.34%	2.15%	3.32%

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. In particular, we welcome engagement on the development work to enhance de-rating factors for embedded technologies described in Section 2.5.2. Any changes to de-rating factor methodologies will require consultation with industry

4.2 Interconnectors

Interconnectors are eligible to participate in both the 2022/23 T-1 and 2025/26 T-4 auctions except where they already have been awarded a Capacity Market agreement. All known interconnectors were awarded contracts in the 2022/23 T-3 auction, therefore no results for 2022/23 T-1 interconnector de-rating factors appear in this document. 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, Ofgem 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 de-rating factors to apply to individual interconnectors. The de-rating factor ranges in the ECR do not account for technical reliability, which is determined by BEIS.

As we did for the 2020 ECR, we published a briefing note in April 2021 providing an early view of the interconnector modelling in the 2021 ECR. This also gave stakeholders an opportunity to provide feedback directly to the PTE to consider in scrutinising our modelling and providing their recommendation to the Secretary of State[60]. We welcome further feedback and engagement on our interconnector modelling from all stakeholders and we are also intending to host a webinar on our interconnector modelling as we did last year[61].

[60] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Interconnector%20Modelling%20Briefing%20Note.pdf
[61] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/IC%20Webinar%20Presentation%20v1.pdf

Further details on our interconnector modelling assumptions are included in Annex A.10. This is based on the outcome of a development project discussed in Section 2.5.2 in response to recommendation 55 of the 2020 PTE Report.

4.2.1 Methodology

The methodology in this year's ECR is broadly similar to our approach in the 2020 ECR[62]. We have implemented some smaller changes outlined below. This represents an evolution of the previous methodology with smaller year-on-year changes compared with the 2020 ECR. This means that:

- We continue to assume that interconnectors will be participating directly in the next round of CM auctions rather than direct cross-border participation
- We continue to assess the potential contribution to security of supply from interconnectors during stress periods that strictly meet the condition where expected energy unserved is greater than zero[63] (i.e. we still have unserved energy after considering imports)
- We continue to use stochastic modelling of generator outages in Europe and sensitivity analysis to assess the potential impact of supply and demand uncertainty in Europe
- We continue to use our pan-European market model BID3 developed by Afry[64] and make use of the 'LOLE' module that was implemented last year
- The ECR only covers our modelling of future European electricity markets and doesn't include any information relating to the 'historical floor' that has not been included since the 2018 ECR.

Since last year, we have implemented a small technical change in our methodology. This relates to how we scaled thermal capacity in neighbouring markets to bring the supply-demand balance closer to what may be expected based on their current / assumed reliability standards. This was justified on the basis that the supply outlook in Europe was delivering more capacity than necessary to meet their reliability standards. In the 2020 ECR, we simulated a range of sensitivity levels (e.g. 90% scaling, 80% scaling,...). We then used an assumed security of supply level in the market that the sensitivity affected to determine which scaling level was credible and therefore included in the ECR. We intend to use a similar process for ECR 2021, however the methodology used to determine the security of supply level has been refined to align more closely with the methodology developed by European Network of Transmission System Operators for Electricity (ENTSO-E) on direct cross-border foreign participation in capacity markets. The new methodology involves scaling thermal plant by varying levels in all modelled European markets to determine what level of thermal capacity reduction results in the market in question meeting the assumed security of supply standard. The methodology used for ECR 2020 scaled thermal plant in all European markets by the same percentage. The new methodology allows us to get all modelled European markets to their assumed security standard by varying the thermal scaling in each market.

[62] See Chapter 4.2 in https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202020.pdf
[63] 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
[64] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite

The changes we made in the 2020 ECR meant that our methodology is already well-aligned to the principles in the methodology developed by the ENTSO-E[65] on direct cross-border participation. This has now been approved by the European Union Agency for the Cooperation of Energy Regulators (ACER).[66] We therefore consider the changes we implemented last year to be more robust, which justifies continued use of our approach in the 2021 ECR.

Data sources

Since last year we have procured a new core BID3 data set from Afry[67]. This includes three additional weather years that allow us to simulate correlated wind, solar and demand across Europe for the period 1985 – 2018 inclusive (in the 2020 ECR, we modelled weather years 1985 – 2015). The additional weather years will help us capture more variety in weather patterns across Europe and should improve the robustness of the modelling. It now means that we simulate the tightest 102 periods (34 historic years * 3 hours LOLE). The data set from Afry also includes updated supply and demand projections for Europe.

In the 2020 ECR, our supply and demand projections for Europe were based on ENTSO-E's scenarios in the 2018 Ten Year Network Development Plan (TYNDP). We had intended to update our supply and demand projections for Europe based on ENTSO-E's 2020 TYNDP scenarios. We have encountered some technical difficulties such that we have not been able to produce reliable simulations in BID3 with this data set. Therefore, we have used the data we have procured from Afry to also inform our supply and demand projections in European countries for the 2021 ECR. We consider this to be preferable to retaining the previous ENTSO-E assumptions based on the 2018 TYNDP that are likely to be out-of-date by now. This approach means we will have a single scenario for Europe in the 2021 ECR modelling, although our extensive use of sensitivities enables us to cover the credible supply and demand uncertainties in Europe. Assumptions for Great Britain are based on the 2021 FES (See Chapter 3).

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). Using the methodology used up to ECR 2019, a 1 GW unit with availability of 90% would be assumed to have 900 MW available capacity for 100% of the time. The current 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 discrete thermal 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[68]). 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.

[65] 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
[66] https://www.acer.europa.eu/Media/News/Pages/ACER-decides-on-common-rules-for-cross-border-participation-in-electricity-capacity-mechanisms-.aspx
[67] This is Afry's Central European scenario
[68] We used 1000 cases in our 2020 and 2021 ECR analysis

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

We use sensitivities to assess the potential uncertainty of supply and demand in Europe beyond the assumptions in the scenario. The changes to our methodology enabled by the enhanced functionality offered by the new LOLE module in BID3 means that we have completed around 750,000 simulations[69] each covering 34 years' historic weather for the 2025/26 T-4 auction.

Table 20 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 in this chapter.

Table 20: 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.
Belgium Thermal	Scaling thermal plant capacity in Belgium from 100% to 0% in 10% steps.	Belgium is due to phase out its nuclear fleet by the end of 2025.
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.
France Thermal	Scaling thermal plant capacity in France from 100% to 0% in 10% steps.	France has significant thermal capacity (including Nuclear). Nuclear type faults and acceleration in decarbonisation may result in lower available capacity.
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 (both hard and lignite) 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 (both markets) from 100% to 0% in 10% steps.	Denmark has coal capacity which may be phased out ahead of schedule due to environmental concerns.
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 34 weather years should cover a range of hydro inflow, it is possible that these years do not cover all possible inflow levels.
Spain Thermal	Scaling thermal plant capacity in Spain from 100% to 0% in 10% steps.	Spain has significant thermal capacity which may be phased out early to decarbonise.

[69] We have 5 scenarios in FES (Base Case + 4 scenarios) each simulated with 150 sensitivities and 1000 outages cases, giving a total of 750,000. Prior to the 2019 ECR we used a full hourly dispatch in which we only modelled around 20 cases and discarded the vast majority of the data as it didn't correspond to a stress period.

Sensitivities simulated, but not considered in the results		
Sensitivity Name	**Description**	**Justification**
European Demand	Demand in all modelled European markets increased by 1% to 10% in 1% 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.
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.
Germany Wind	Scaling onshore and offshore wind in Germany from 100% to 150% in 5% steps.	Germany has one of the largest wind markets in Europe and may have an appetite to increase this further.
Ireland Wind	Scaling onshore and offshore wind in Ireland from 100% to 150% in 5% steps.	Ireland has very good wind resources and may accelerate their wind construction programme.
France Wind	Scaling onshore and offshore wind in France from 100% to 150% in 5% steps.	France has a desire to reduce reliance on nuclear power and pivot towards renewable energy.
North Sea Offshore Wind	Scaling offshore wind in Belgian, Dutch and Danish North Sea territorial waters from 100% to 150% in 5% steps.	The North Sea has excellent potential for offshore wind and there has been significant interest in utilising this resource.

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 scenario assumptions. These assumptions show that there is currently a surplus of capacity in Europe with many countries reporting LOLE values lower than their Reliability Standards[70]. 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. We believe this justifies the inclusion of more downside sensitivities. Had the scenario assumptions led to an adequacy outlook with European countries closer to their Reliability Standards, then the sensitivities modelled would be more symmetric.

There is considerable scope, though, 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 led to three 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. The third approach relates to Belgian nuclear capacity, which is all due to close by the end of 2025 (i.e. during the 2025/26 T-4 delivery period). The Belgium Thermal sensitivity is set to simulate the complete closure of all Belgian nuclear capacity before the start of the 2025/26 T-4 delivery period.

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.

[70] For example, ENTSO-E 2019 Mid-term Adequacy Forecast report: https://www.entsoe.eu/outlooks/midterm/

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.[71] 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.[72] 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 approved by ACER[73]. 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 20 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 LOLE was calculated for each market and thermal scaling level. The credible threshold was determined to be the point at which the LOLE was approximately 3 hours on 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.

France Nuclear 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)[74]. 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. In addition, the new EPR unit at Flamanville is due to commission in time for the 2025/26 T-4 delivery period. However, this is the first unit of its kind in France and there may be delays with construction or teething trouble. An additional 2 GW of capacity loss has been added to the 10 GW for unplanned outages. Therefore, a sensitivity of 12 GW loss of nuclear capacity in France is included. Furthermore, this sensitivity has been modified to reduce demand side response (DSR) capacity in France. The DSR capacity in France has been reduced as there is significant uncertainty as to the growth rate of DSR in France[75].

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 and Belgium nuclear sensitivity (i.e. only those shown in Table 20) is shown in the results tables and figures as the 'European LOLE standard'. The

[71] 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.
[72] https://consultations.entsoe.eu/entso-e-general/proposal-for-voll-cone-and-reliability-standard-me/
[73] https://www.acer.europa.eu/Media/News/Pages/ACER-decides-on-common-rules-for-cross-border-participation-in-electricity-capacity-mechanisms-.aspx
[74] 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), winter 2019/20 (typically below 50 GW) and winter 2020/21 (around 50 GW). Based on nuclear generation output data available on RTE's website: https://www.rte-france.com/en/eco2mix/eco2mix-mix-energetique-en.
[75] For example, RTE's 2019 generation adequacy report indicates 4.1 – 5.3 GW DSR by 2025. https://assets.rte-france.com/prod/public/2020-09/2019_generation_adequacy_report.pdf

France nuclear additional sensitivity is shown as the 'France Nuclear -12GW & DSR Reduced'. The Belgium nuclear sensitivity is shown as 'Belgium Nuclear Closure'.

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 21: 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	2021 Future Energy Scenarios – Base Case
Consumer Transformation	CT	2021 Future Energy Scenarios – Consumer Transformation
System Transformation	ST	2021 Future Energy Scenarios – System Transformation
Leading the Way	LW	2021 Future Energy Scenarios – Leading the Way
Steady Progression	SP	2021 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 22 for 2025/26. Where there are 'N/A' in these tables, that country is not connected to Great Britain in that scenario and delivery year. De-rating factors are not calculated for 2022/23 as all interconnectors forecast to connect by this delivery year already have a Capacity Market contract for 2022/23.

GB demands were increased significantly (by scaling the demand) to ensure that there was load loss in all simulated time periods. The 102 time periods with the most load loss were simulated in BID3. This is an average of 3 hours LOLE across 34 historic 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 22: Simulation results: 2025/26 imports as percentage of interconnector capacity

	ECR 2020 2024/25 T-4		Scenarios					Most onerous sensitivity				
Country	Min.	Max.	BC	CT	ST	LW	SP	BC	CT	ST	LW	SP
Ireland	19	66	80	97	97	89	97	18	12	10	12	12
France	45	91	95	97	96	95	96	62	66	68	59	62
Belgium	39	88	80	82	82	78	78	32	28	29	22	25
Netherlands	34	84	85	88	88	84	87	55	59	61	49	54
Germany	54	83	N/A	N/A	N/A	79	N/A	N/A	N/A	N/A	43	N/A
Denmark	32	80	84	87	87	79	86	57	61	63	47	55
Norway	91	100	94	96	96	93	95	81	83	85	78	80

4.2.4 Country de-ratings

The results for each scenario averages are shown in Figure 15 to Figure 21 and Table 23 to Table 29.

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.

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 2025/26. The electricity networks of continental Europe are all highly interconnected.

Ireland:

The modelled ranges for Ireland are 10% to 97% for 2025/26.

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.

Eirgrid is forecasting there will be downward pressure on generation in its 2020 All-Island Generation Capacity Statement[76]. This is partly due to the Irish Capacity Market currently targets 8 hours LOLE through Capacity Market auctions. It should be noted that the scenarios have a greater thermal capacity in Ireland than that which appears in the 2020 All-Island Generation Capacity Statement.

The results for Ireland show a very wide range. The scenario values a high because our scenario has a large amount of thermal capacity. This is included in the scenario because although Ireland has an LOLE standard of 8 hours it has procured sufficient capacity in its capacity market to remain well within this standard. The European LOLE standard sensitivity demonstrates the reduction in interconnector de-rating factor if Ireland were to close enough thermal plant to meet their security of supply standard. Unlike all the other markets shown in this section Ireland has no interconnection to other markets (ignoring GB) and therefore cannot act as an intermediary for excess capacity from other markets.

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

[76] http://www.eirgridgroup.com/site-files/library/EirGrid/All-Island-Generation-Capacity-Statement-2020-2029.pdf

Figure 15: Irish interconnector de-rating factors 2025/26

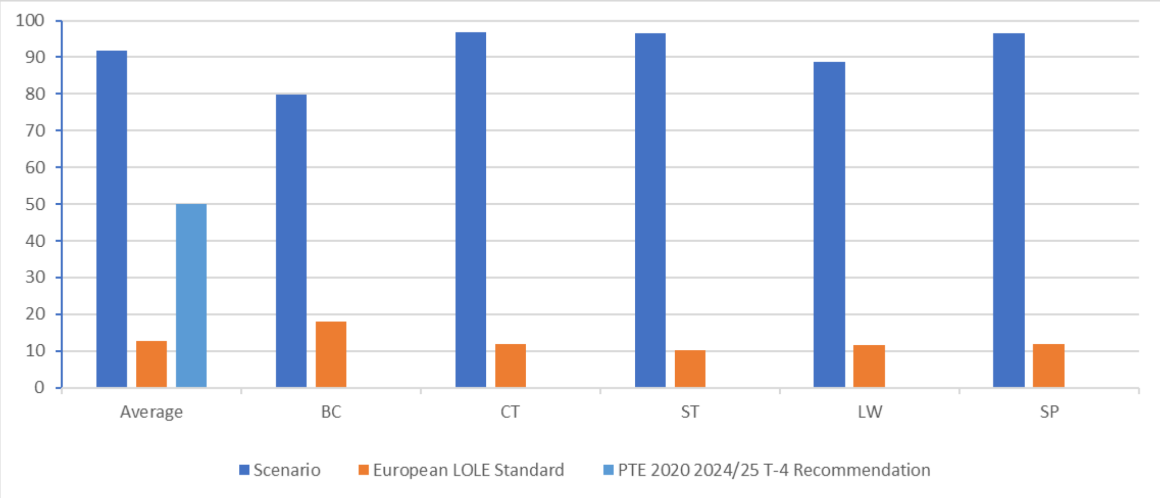


Table 23: Irish interconnector de-rating factors 2025/26

Calculation	Average	BC	CT	ST	LW	SP
Scenario	92	80	97	97	89	97
Most onerous sensitivity	13	18	12	10	12	12
	N/A	European LOLE Standard	European LOLE Standard	European LOLE Standard	European LOLE Standard	European LOLE Standard

France:

The modelled ranges for France are 59% to 97% for 2025/26.

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 further in the future. France is well interconnected to other markets in Europe which gives access to excess capacity in these markets. The French de-rating factor is particularly affected by the French nuclear sensitivity.

Figure 16: French interconnector de-rating factors 2025/26

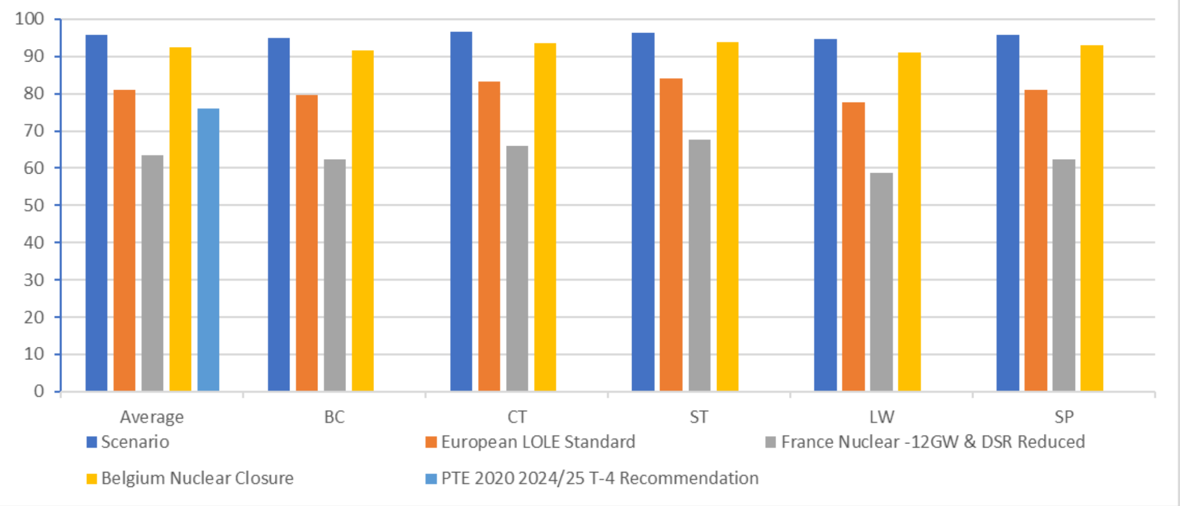


Table 24: French interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	96	95	97	96	95	96
European LOLE Standard	81	80	83	84	78	81
France Nuclear -12GW & DSR Reduced	63	62	66	68	59	62
Belgium Nuclear Closure	93	92	94	94	91	93
Most onerous sensitivity	63	62	66	68	59	62
	N/A	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced

Belgium:

The modelled ranges for Belgium are 22% to 82% for 2025/26.

Belgium plans to phase out nuclear power by 2025, this is the justification for carrying out the Belgium nuclear closure sensitivity. Since nuclear capacity makes up a significant proportion of the dispatchable installed capacity in Belgium at present and Belgium has relatively low levels of interconnection to other European markets the closure of the nuclear plant has a significant effect on the interconnector de-rating factors.

Figure 17: Belgium interconnector de-rating factors 2025/26

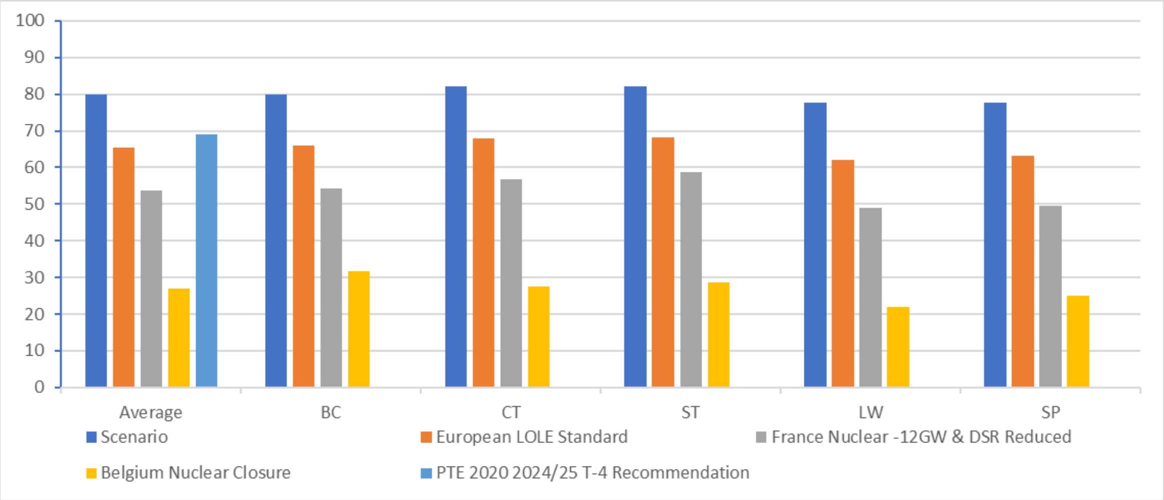


Table 25: Belgium interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	80	80	82	82	78	78
European LOLE Standard	65	66	68	68	62	63
France Nuclear -12GW & DSR Reduced	54	54	57	59	49	50
Belgium Nuclear Closure	27	32	28	29	22	25
Most onerous sensitivity	27	32	28	29	22	25
	N/A	Belgium Nuclear Closure	Belgium Nuclear Closure	Belgium Nuclear Closure	Belgium Nuclear Closure	Belgium Nuclear Closure

Netherlands:

The modelled ranges for Netherlands are 49% to 88%.

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 18: Netherlands interconnector de-rating factors 2025/26

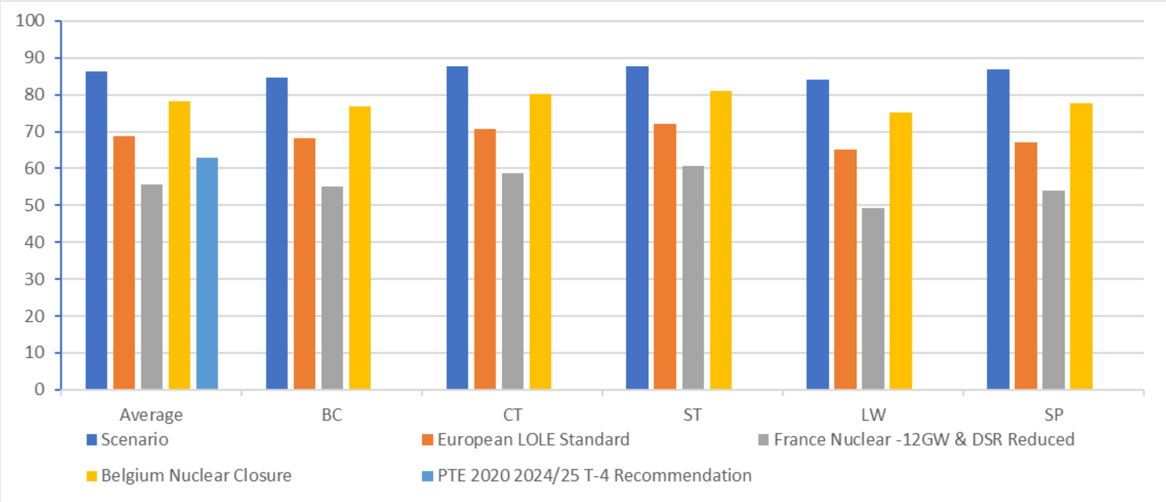


Table 26: Netherlands interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	86	85	88	88	84	87
European LOLE Standard	69	68	71	72	65	67
France Nuclear -12GW & DSR Reduced	56	55	59	61	49	54
Belgium Nuclear Closure	78	77	80	81	75	78
Most onerous sensitivity	56	55	59	61	49	54
	N/A	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced

Germany:

Direct interconnection to Germany only appears in the Leading the Way scenario for 2025/26. The modelled ranges for Germany are 43% to 79%. Note that there was no PTE recommendation for Germany based on in the 2020 ECR.

Figure 19: Germany interconnector de-rating factors 2025/26

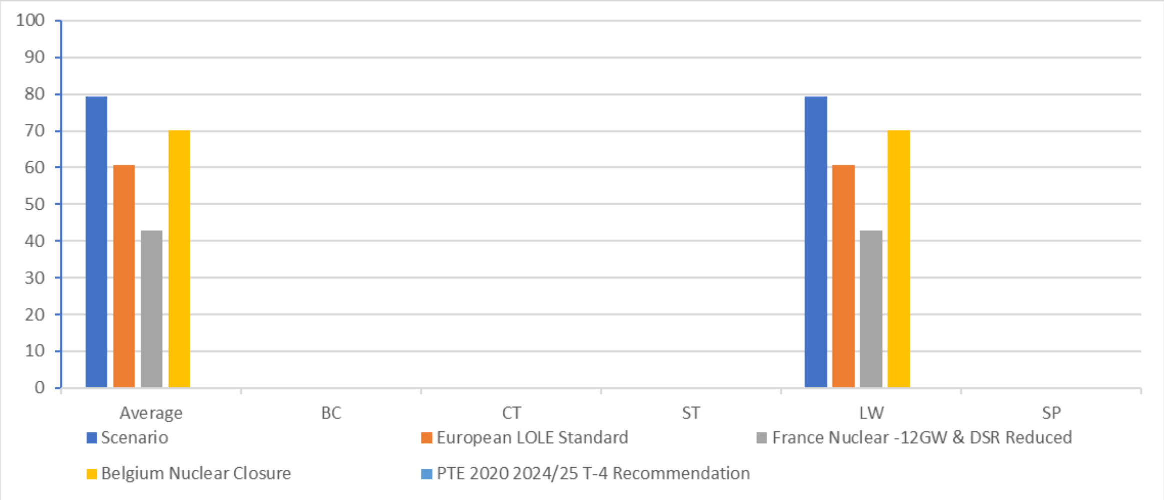


Table 27: Germany interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	79	N/A	N/A	N/A	79	N/A
European LOLE Standard	61	N/A	N/A	N/A	61	N/A
France Nuclear -12GW & DSR Reduced	43	N/A	N/A	N/A	43	N/A
Belgium Nuclear Closure	70	N/A	N/A	N/A	70	N/A
Most onerous sensitivity	43	N/A	N/A	N/A	43	N/A
	N/A	N/A	N/A	N/A	France Nuclear -12GW & DSR Reduced	N/A

Denmark:

The modelled ranges for Denmark are 47% to 87%.

Figure 20: Denmark interconnector de-rating factors 2025/26

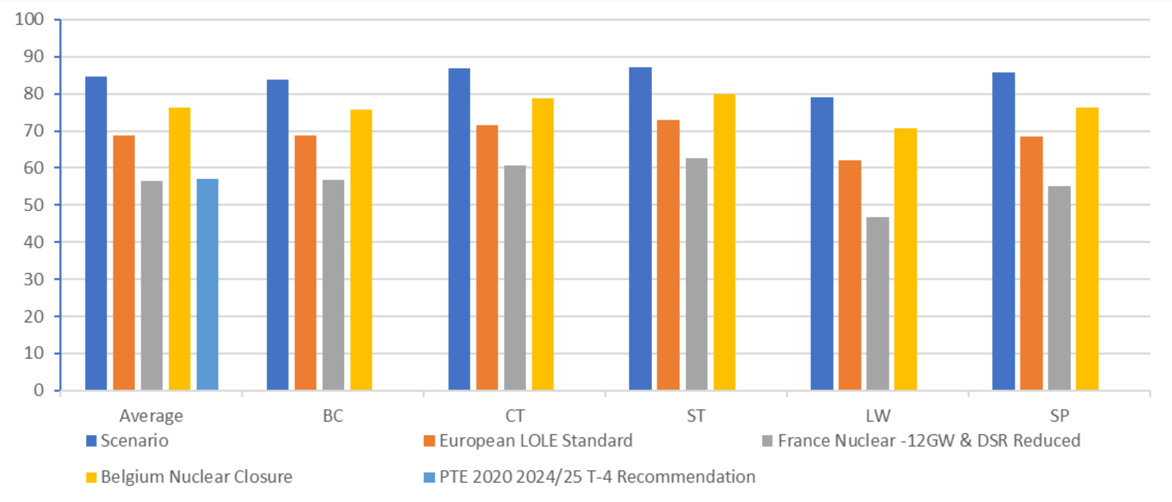


Table 28: Denmark interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	84	84	87	87	79	86
European LOLE Standard	69	69	72	73	62	68
France Nuclear -12GW & DSR Reduced	56	57	61	63	47	55
Belgium Nuclear Closure	76	76	79	80	71	76
Most onerous sensitivity	56	57	61	63	47	55
	N/A	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced

Norway:

The modelled ranges for Norway are high across all scenarios giving a range of 78% to 96% for 2025/26.

The high interconnector de-rating factors are due to the large volume of hydro capacity in Norway. The European LOLE standard sensitivity in Norway considers a 10% reduction in hydro availability. The France sensitivity is the most onerous as spare capacity in Norway is required to meet shortfalls in central Europe due to the reduction in French capacity.

Figure 21: Norway interconnector de-rating factors 2025/26

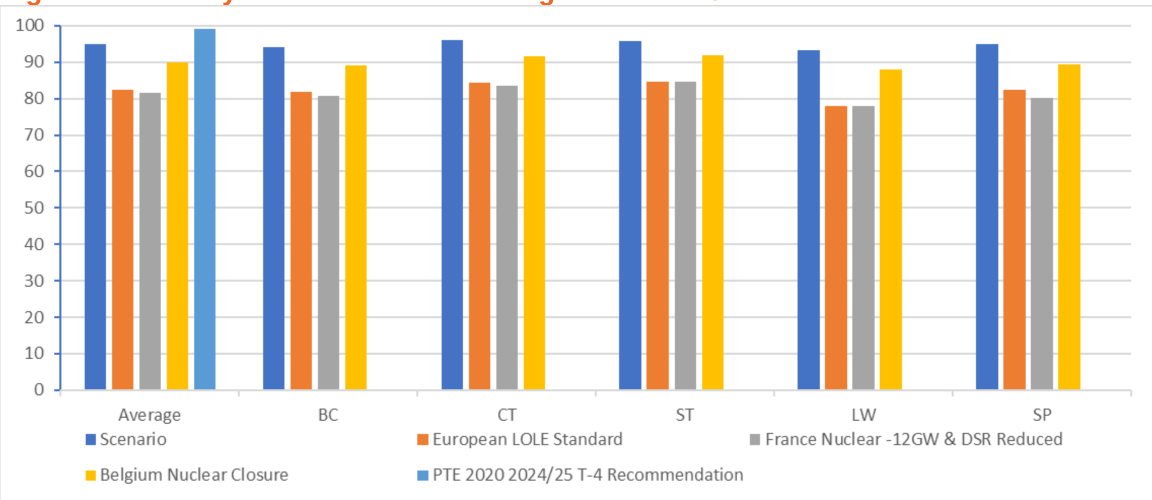


Table 29: Norway interconnector de-rating factors 2025/26

Calculation	Avg.	BC	CT	ST	LW	SP
Scenario	95	94	96	96	93	95
European LOLE Standard	82	82	84	85	78	82
France Nuclear -12GW & DSR Reduced	81	81	83	85	78	80
Belgium Nuclear Closure	90	89	92	92	88	89
Most onerous sensitivity	81	81	83	85	78	80
	N/A	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced	France Nuclear -12GW & DSR Reduced

Summary

The interconnector de-rating factor ranges has been selected from the highest and lowest value from the results table for each country. 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.

It should be noted that both Ireland and Belgium exhibit particularly large ranges. For Ireland this is due to it being an isolated market when compared to the other markets. Our scenario has a high thermal capacity in Ireland which results in excess capacity to supply GB. The European LOLE sensitivity brings Ireland to its assumed LOLE standard (8 hours which is higher than the assumption for all other markets). This results in a large reduction in thermal capacity in Ireland and therefore the there is little spare capacity to export power to GB. For Belgium our scenario assumes that some nuclear capacity remains (the last nuclear unit in Belgium is due to close towards the end of 2025; during the 2025/26 T-4 delivery period). The Belgium nuclear closure sensitivity assumes that all nuclear units in Belgium have closed by the start of the 2025/26 T-4 delivery period. This significant reduction in capacity results in a significant reduction in de-rating factor.

The French sensitivity is the most onerous sensitivity in all markets except Ireland and Belgium. The large reduction in French capacity results in shortfalls across continental Europe and therefore any excess capacity in Europe will be used primarily to meet any shortfalls on the continent before capacity is supplied to GB. This is due to GB being on the periphery of Europe and therefore tends to incur higher losses when importing power. The objective function of the modelling is to reduce load loss across the modelled markets in Europe and therefore supplying the markets which have the lowest loss access to spare capacity will be prioritised.

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. The ranges for each country are shown in Table 30. Although in some cases the ranges are wide, we consider them to be credible given the uncertainty on future generation capacity in Europe.

Table 30: De-rating factor ranges by country for 2025/26

Country	Minimum	Maximum
Ireland	10	97
France	59	97
Belgium	22	82
Netherlands	49	88
Germany	43	79
Denmark	47	87
Norway	78	96

5. Results and Recommendation for T-1 Auction for 2022/23

Our recommendation for the target capacity for the T-1 auction for 2022/23 delivery is **4.5 GW**. This chapter presents the detailed modelling results to support our recommendation. Further information on potential capacity requirements in the period out to 2035/36 can be found in Section 3.11.

5.1 Scenarios and Sensitivities to Model

The agreed scenarios and sensitivities to model were:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Steady Progression (SP)
- 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): Up to 5200 MW in 400 MW increments
- Over-Delivery (OVER DEL): Up to 3200 MW in 400 MW increments

5.2 Results

Table 31 shows the de-rated capacity required to meet the Reliability Standard of 3 hours LOLE for each scenario and sensitivity modelled. It also shows the capacity outside of the CM (including previously contracted capacity), the total de-rated capacity and the ACS peak demand for each case.

All cases consider known non-delivery where capacity providers that secured an agreement covering delivery year 2022/23 from a previous auction can no longer meet their obligations. This known non-delivery totals 1.9 GW (de-rated) since the 2019 ECR (which contained our recommendation for the 2022/23 T-3 auction). We also assume additional non-delivery in the Base Case and FES scenarios. Non-delivery in the Base Case is our best view based on market intelligence of capacity providers who we do not currently expect to meet their obligations. The Base Case assumes 0.8 GW non-delivery for 2022/23. Non-delivery in the FES scenarios reflect uncertainty of capacity providers that may be at risk of not meeting their obligations. There is no additional non-delivery in the ST scenario (which is similar to the Base Case), but the other FES scenarios assume additional non-delivery compared to the Base Case of: 0.7 GW in LW, 0.9 GW in CT and 1. GW in SP for 2022/23 This can be seen in Table 31 where the previously contracted capacity for these scenarios differs from the Base Case.

Furthermore, all scenarios and sensitivities include 0.4 GW over-delivery for 2022/23 based on the outcome of a development project addressing recommendation 54 from the 2020 PTE report. This is eligible capacity assumed to stay open without a CM agreement or secondary trade – this has been modelled by increasing the non-CM autogeneration de-rated capacity by 0.4 GW. This project (see Section 2.5.2) recommended that a small amount of over-delivery is likely to materialise for the T-1 year and therefore could be assumed in the Base Case (and scenarios). Further over-delivery is possible but less certain and has been modelled via over-delivery sensitivities

The results reflect our latest view of de-rating factors and Transmission Entry Capacity (TEC) values for CM units. Two changes in particular are worth highlighting. Firstly, the de-rating factors for duration limited storage have been revised since the T-4 auction for 2020/21 such that the de-rating factors now reflect the duration capability of storage providers. As a result, our estimate of the de-rated capacity of duration limited storage awarded multi-year agreements from CM auctions up to and including the T-4 auction for 2020/21 is now just over 0.4 GW lower than has been contracted. Secondly, we model all transmission connected units using the latest values for technology de-rating factors and Transmission Entry Capacity (TEC). This results in a de-rated capacity that is 0.8 GW lower than was previously contracted. These two changes combined with the known non-delivery (1.9 GW) and assumed non-delivery (0.8 GW) have effectively reduced the estimate of the previously contracted capacity for 2022/23 in the Base Case from the reported[77] figure of over 49.9 GW to around 46.0 GW – a shortfall of over 3.9 GW that needs to be secured again.

[77] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20T4%20DY2024-25%20Final%20Report.pdf

Table 31: Modelled de-rated capacities and peak demands – 2022/23

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW) in sensitivity	Total derated capacity (GW)	ACS Peak (GW)
Over Delivery Sensitivity: 3200	BC_OVER_DEL_3200	-1.1	62.4	46*	3.2	61.3	58.0
Warm Winter	BC_WARM	-0.9	59.6	46.0	0.0	58.7	58.0
Over Delivery Sensitivity: 2800	BC_OVER_DEL_2800	-0.7	62.0	46*	2.8	61.3	58.0
Over Delivery Sensitivity: 2400	BC_OVER_DEL_2400	-0.3	61.6	46*	2.4	61.3	58.0
Leading the Way	LW	-0.1	58.2	45.3	0.0	58.1	55.0
Over Delivery Sensitivity: 2000	BC_OVER_DEL_2000	0.1	61.2	46*	2.0	61.3	58.0
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	0.5	60.8	46*	1.6	61.3	58.0
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	0.9	60.4	46*	1.2	61.3	58.0
Low Demand	BC_LOW_DEMAND	0.9	59.2	46.0	0.0	60.1	56.8
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	1.3	60.0	46*	0.8	61.3	58.0
High Availability	BC_HIGH_AVAIL	1.3	59.9	46.7	0.0	61.2	58.0
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	1.7	59.6	46*	0.4	61.3	58.0
Base Case	BC	2.1	59.2	46.0	0.0	61.3	58.0
Consumer Transformation	CT	2.5	58.3	45.1	0.0	60.7	57.4
Non Delivery Sensitivity: -400	BC_NON_DEL_400	2.5	58.8	46*	-0.4	61.3	58.0
System Transformation	ST	2.5	59.3	46.0	0.0	61.8	58.5
Non Delivery Sensitivity: -800	BC_NON_DEL_800	2.9	58.4	46*	-0.8	61.3	58.0
High Demand	BC_HIGH_DEMAND	3.2	59.3	46.0	0.0	62.5	59.2
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	3.3	58.0	46*	-1.2	61.3	58.0
Cold Winter	BC_COLD	3.4	58.8	46.0	0.0	62.1	58.0
Low Availability	BC_LOW_AVAIL	3.6	58.1	44.7	0.0	61.7	58.0
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	3.7	57.6	46*	-1.6	61.3	58.0
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	4.1	57.2	46*	-2.0	61.3	58.0
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	4.5	56.8	46*	-2.4	61.3	58.0
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	4.9	56.4	46*	-2.8	61.3	58.0
Non Delivery Sensitivity: -3200	BC_NON_DEL_3200	5.3	56.0	46*	-3.2	61.3	58.0
Steady Progression	SP	5.6	58.0	44.9	0.0	63.5	60.2
Non Delivery Sensitivity: -3600	BC_NON_DEL_3600	5.7	55.6	46*	-3.6	61.3	58.0
Non Delivery Sensitivity: -4000	BC_NON_DEL_4000	6.1	55.2	46*	-4.0	61.3	58.0
Non Delivery Sensitivity: -4400	BC_NON_DEL_4400	6.5	54.8	46*	-4.4	61.3	58.0
Non Delivery Sensitivity: -4800	BC_NON_DEL_4800	6.9	54.4	46*	-4.8	61.3	58.0
Non Delivery Sensitivity: -5200	BC_NON_DEL_5200	7.3	54.0	46*	-5.2	61.3	58.0

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 2022/23 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 3.2 GW over-delivery and 5.2 GW non-delivery sensitivities define the extremes of the capacity to secure range for 2022/23 (-1.1 GW to 7.3 GW). In the Leading the Way scenario, Warm Winter sensitivity and the highest over-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.

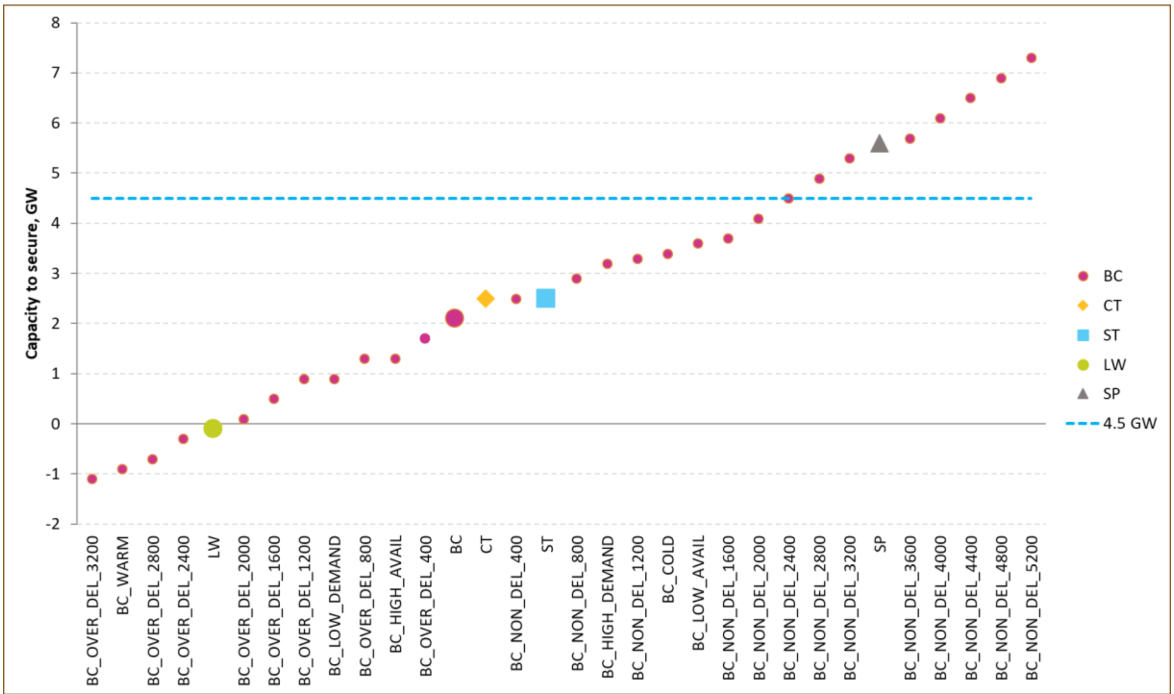
5.3 Recommended Capacity to Secure

The results in Table 31 show there is a wide range in the capacity required to meet 3 hours LOLE from -1.1 GW to 7.3 GW. If we knew which case would actually occur in 2022/23, then we could simply recommend the capacity associated with this case as the optimal target capacity. However, we do not know what will actually happen in 2022/23. This means that if we were to pick a capacity to secure from one of the values listed in Table 31 then there is a high risk that this will not be the one associated with what actually happens. This could mean that we secure too much capacity resulting in an LOLE below 3 hours or that we secure too little capacity resulting in an LOLE above 3 hours. In either case, the total cost is non-optimal as either the cost of capacity is higher than needed or the cost of unserved energy is higher than expected for an LOLE of 3 hours.

We use the Least Worst Regret (LWR) methodology to select one of the values from Table 31 as our recommended target capacity for the T-1 auction for 2022/23. The LWR methodology considers the total cost for each case in the event that any one of the other cases actually happens (i.e. it assesses all potential options for over- or under-securing capacity). For each case in Table 32, there will be a worst-case outcome (e.g. if we select 7.3 GW then the worst-case outcome would be if -1.1 GW was to occur). The LWR[78] calculates the cost for the worst-case outcome in each case and selects the case whose worst-case outcome has the lowest cost. The LWR assumes a net CONE of £49/kW/year and an energy unserved cost (or value of lost load) of £17,000/MWh, which is consistent with the Government's Reliability Standard. This means that our recommended target capacity based on the LWR outcome 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. Further information on the LWR methodology is provided in the Annex A.7.

The outcome of the LWR calculation is a recommended capacity to secure of **4.5 GW**. This is the capacity associated with the 2.4 GW non-delivery sensitivity. This outcome excludes any capacity secured for 2022/23 in earlier auctions assumed in the Base Case. Figure 22 illustrates the full range of potential capacity requirements and identifies the LWR outcome (4.5 GW). Scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. The Steady Progression scenario has a higher requirement than the other scenarios, due to additional non-delivery assumed and a higher peak demand.

Figure 22: Least Worst Regret outcome and recommended capacity to secure compared to individual scenario / sensitivity runs – 2022/23.



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.

[78] 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).

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 was to occur in 2022/23 that is not covered, then the LOLE could be greater than 3 hours. This could mean mitigating actions (e.g. voltage reduction, max gen. service and emergency assistance from interconnectors) are deployed 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. Figure 22 shows that the outcome of the LWR calculation covers 24 of the 32 cases.

5.3.2 Adjustments to Target 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 final T-1 auction target, a number of adjustments to the recommended value 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. Although these providers are now eligible for CM agreements, if they opt out of prequalification and are assumed to be operational in 2022/23, an adjustment may still be required) – ***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, the recommended capacity to secure through the 2022/23 T-1 auction could be:

- 4.5 GW - ***v*** - ***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.

5.3.3 Comparison with T-3 for 2022/23 recommendation

In our 2019 ECR[79], we recommended a capacity to secure for 2022/23 of 45.4 GW derived from the 0.4 GW non-delivery sensitivity. Of this, the Secretary of State held back 1.2 GW for the T-1 auction for 2022/23 leaving an initial target capacity of 44.2 GW for the T-3 auction. Following pre-qualification, the T-3 auction for 2022/23 target was reduced by the Secretary of State to 44.0 GW with no changes to the 1.2 GW originally set aside for the T-1 auction for 2022/23. The 0.2 GW (net) of adjustments made to the T-3 auction for 2022/23 target comprised of:

- 0.3 GW reduction relating to long-term STOR outside of the CM.
- 0.1 GW increase due to autogeneration assumed to be outside of the CM participating in prequalification.

In general, when compared to the analysis for 2022/23 in the 2019 ECR that ultimately led to the 1.2 GW set aside by the Secretary of State for the T-1 auction, the 2021 ECR LWR outcome for 2022/23 is 3.3 GW higher than the 1.2 GW set aside. This difference is the result of the following increases and decreases.

The increases total 5.9 GW:

- 0.2 GW net increase relating to the demand curve adjustments made in 2019 following prequalification for the T-3 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 2021 Base Case generation assumptions are different to the 2019 Base Case assumptions.
- Non-delivery since the 2019 Base Case, totalling 1.9 GW in 2022/23 (this is the known non-delivery - see Section 5.2).
- An increase of 0.8 GW due to additional non-delivery assumed in the Base Case based on market intelligence of capacity providers who we do not currently expect to meet their obligations for 2022/23.
- The contracted conventional capacity from previous T-3 and T-4 auctions being 0.8 GW greater than the de-rated TEC (see Section 5.2).
- An increase of less than 0.1 GW due to a small change in estimated de-rated storage awarded multi-year contracts from the 2020/21 T-4 auction onwards (>0.4 GW reduction in the 2021 ECR compared to a <0.4 GW reduction in the 2019 ECR for 2022/23).
- An increase of 0.1 GW relating to lower levels of assumed opted-out or ineligible (below 1 MW) autogeneration than the 2019 Base Case. Note that the non-CM autogeneration in the 2021 ECR includes the 0.4 GW over-delivery assumed in the Base Case (see Section 5.2)
- A 0.1 GW increase resulting from slightly lower non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely comprised of lower contributions at peak from hydro and other small-scale capacity offset partly by increased biomass.
- A change in the scenarios and sensitivities modelled resulting in the net LWR outcome difference from the Base Case being 2.0 GW higher (2.4 GW non-delivery compared to 0.4 GW non-delivery).

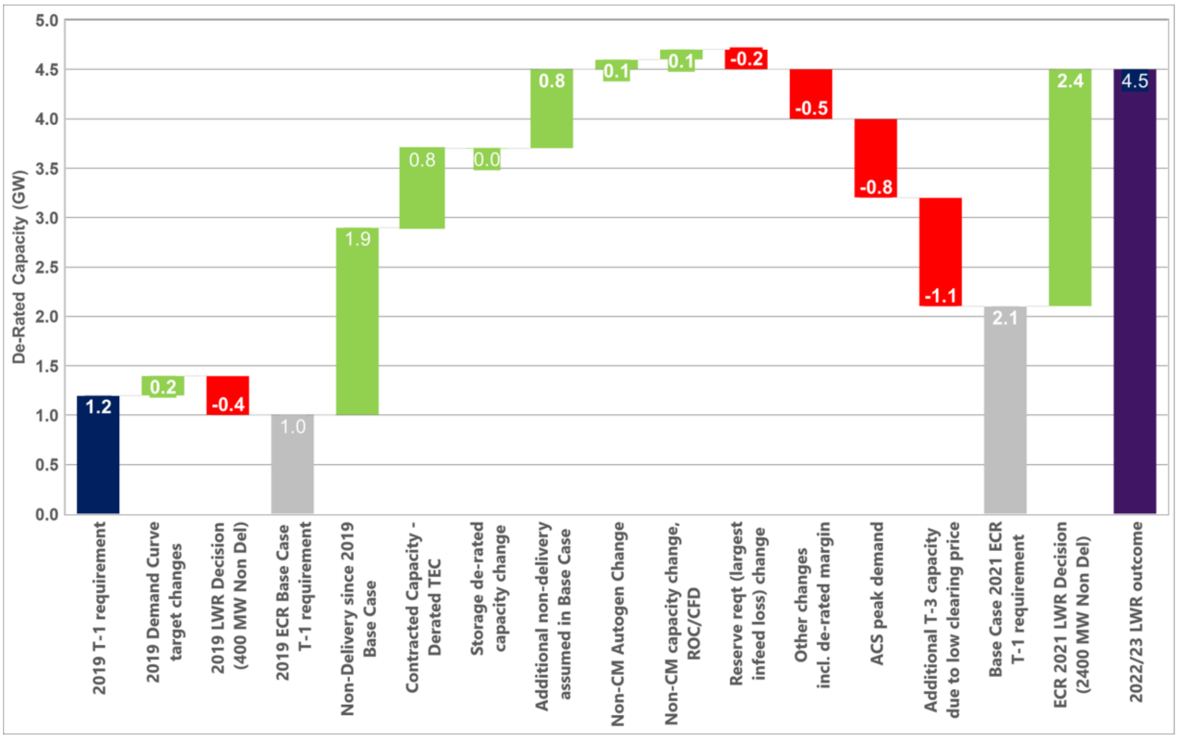
The decreases total 2.6 GW:

[79] Normally in the ECR we compare the T-1 recommendation to the previous T-4 recommendation. However, the 2022/23 T-4 auction was not held as the Capacity Market was suspended. The 2022/23 T-4 auction was replaced by a 2022/23 T-3 auction. Hence we make the comparison to the 2022/23 T-3 recommendation set out in the 2019 ECR.

- A 0.2 GW reduction in reserve for largest infeed loss compared to the 2019 Base Case.
- A 0.5 GW net reduction due to other changes (change in de-rated margin required for 3 hours LOLE compared to the 2019 Base Case and rounding).
- A 0.8 GW reduction due to a lower peak demand in 2022/23 compared to the 2019 Base Case (see section on peak demand changes below).
- A reduction in requirement from over-securing in the T-3 auction for 2022/23 by 1.1 GW due to a low clearing price.

The following waterfall chart, Figure 23, shows how the original 1.2 GW set aside for the T-1 auction for 2022/23 (derived from the 2019 0.4 GW non-delivery sensitivity) has changed into a LWR outcome of 4.5 GW (derived from the 2021 Base Case 2.4 GW non-delivery sensitivity) as a result of the 3.3 GW net increase described above.

Figure 23: Comparison with original T-1 requirement for 2022/23 (de-rated)



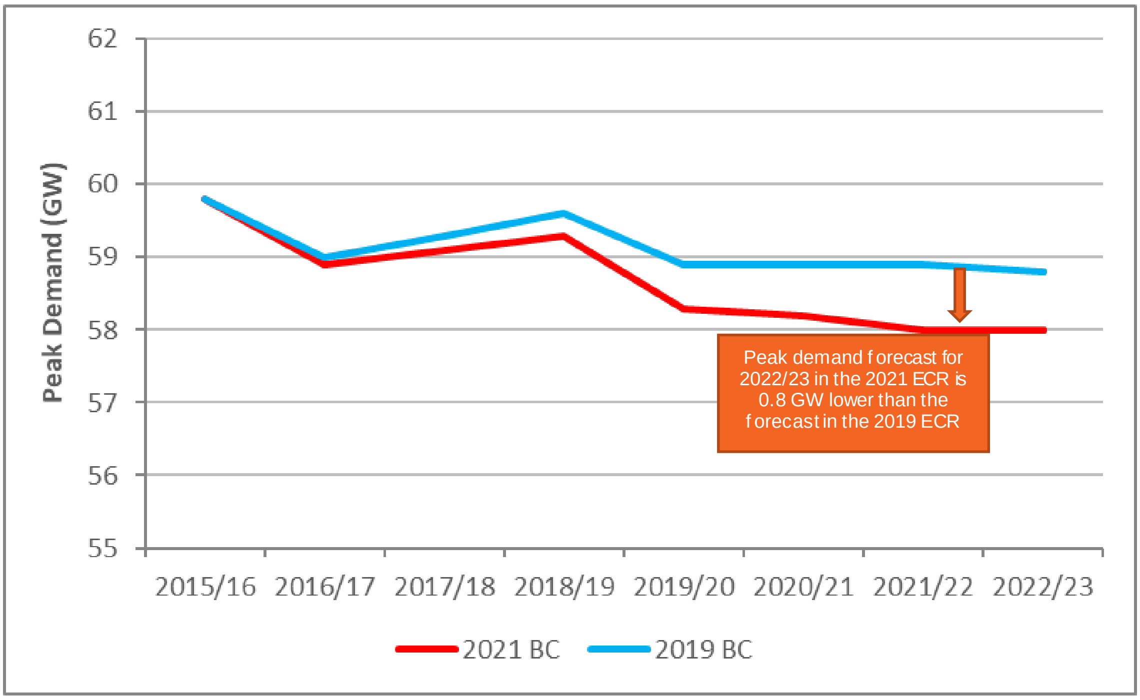
Note: intermediate totals in grey above show requirements for 2019 Base Case and 2021 Base Case

As highlighted above, since the 2019 ECR, the peak demand for 2022/23 has reduced by 0.8 GW.

The chart in Figure 24 compares the underlying ACS peak demand in the 2021 Base Case (2021 BC) to the underlying ACS peak demand in the 2019 Base Case (2019 BC) over the period from 2015/16 to 2022/23. The impact of COVID-19 has been minimal for the ACS peak demand in 2020/21. The impact has also been assumed to have no discernible impact of annual peak demand for future years. The 2021 Base Case for 2022/23 is within 1.4% of the 2019 Base Case. The differences are a combination of changes across each of the sectors.

The letter written to Ofgem under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[80] and the steps taken to taken to improve the peak demand forecast.

Figure 24: Peak Demand Comparison (2021 ECR v 2019 ECR)



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; a sensitive outcome is one that would change every time the included sensitivities changed. 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 32 below.

Table 32: Sensitivity of LWR outcome (4.5 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-3.2 OD	-3.2 OD -Warm	+3.6 OD	-5.2 ND	-5.2 ND -4.8 ND	+5.6 ND
2022/23 outcome	4.5	4.9	4.5	4.5	4.1	4.9

Removing the lowest case (3.2 GW OD) did not change the outcome. Removing the next lowest case (Warm winter) increased the outcome by 0.4 GW to 4.9 GW. Adding an

[80] 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

additional over-delivery case (3.6 GW) kept the outcome at 4.5 GW. Removing the highest case (5.2 GW ND) did not change the outcome. Removing next highest case (4.8 GW ND) as well resulted in a reduction of 0.4 GW to 4.1 GW. Increasing the maximum non-delivery to 5.6 GW increased the original outcome by 0.4 GW to 4.9 GW.

Hence the outcome remains stable when removing either the lowest or highest sensitivity or adding an additional OD sensitivity – the outcome is only changed if an additional ND sensitivity is added.

Although the LWR outcome is stable when the maximum non-delivery is removed, we still believe the most robust maximum non-delivery sensitivity is 5.2 GW to address the risk associated with large thermal and nuclear plants, distributed generation, unproven DSR and interconnection.

To set this in context, in winter 2020/21, we estimate that observed non-delivery during the coldest part of the winter (early December to early February) exceeded 5 GW (see Section 3.10.4). This represents capacity that was not available at all during this period and did not transfer its agreements via secondary trading. This capacity may be subject to penalties and/or termination depending on whether it has demonstrated requirements set out in the Capacity Market Rules. This non-delivery occurred between the T-1 auction for 2020/21 and the winter of delivery year 2020/21 and highlights the potential non-delivery that can occur after the T-1 auction.

6. Results and Recommendation for T-4 Auction for 2025/26

Our recommendation for the target capacity for the T-4 auction for 2025/26 is **44.1 GW**. This chapter presents the detailed modelling results to support our recommendation. Further information on capacity requirements in years out to 2035/36 can be found in Section 3.11.

6.1 Sensitivities to model

The agreed scenarios and sensitivities to model were:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Steady Progression (SP)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): Up to 5600 MW in 400 MW increments
- Over-Delivery (OVER DEL): Up to 4000 MW in 400 MW increments

6.2 Results

Table 33 shows the de-rated capacity required to meet the Reliability Standard of 3 hours LOLE for each scenario and sensitivity modelled. It also shows the capacity outside of the CM (including previously contracted capacity), the total de-rated capacity and the ACS peak demand for each case.

All cases consider known non-delivery where capacity providers that secured an agreement covering delivery year 2025/26 from a previous auction can no longer meet their obligations. This known non-delivery totals over 0.3 GW (de-rated) since the 2020 ECR. In addition, we also assume non-delivery in the Base Case and FES scenarios. Non-delivery in the Base Case is our best view based on market intelligence of capacity providers who we do not currently expect to meet their obligations. The Base Case assumes 0.5 GW non-delivery for 2025/26. Non-delivery in the FES scenarios reflect uncertainty of capacity providers that may be at risk of not meeting their obligations. There is no additional non-delivery assumed in the ST, LW and CT scenarios, but the SP scenario assumes an additional 0.5 GW non-delivery compared to the Base Case for 2025/26.

The results also reflect our latest view of de-rating factors and TEC values for CM units as we described in Section 5.2. In particular, our estimate of the de-rated capacity of duration limited storage awarded multi-year agreements from CM auctions up to and including the 2020/21 T-4 auction, is now around 0.5 GW lower than has been contracted. This change combined with the known non-delivery (0.3 GW) and assumed non-delivery (0.5 GW) have effectively reduced the estimate of the previously contracted capacity for 2025/26 in the Base Case from the reported[81] figure of 8.3 GW to 7.0 GW – a shortfall of 1.3 GW that needs to be secured again.

Table 33: Modelled de-rated capacities and peak demands - 2025/26

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW) in sensitivity	Total derated capacity (GW)	ACS Peak (GW)
Over Delivery Sensitivity: 4000	BC_OVER_DEL_4000	37.3	25.3	7*	4.0	62.6	59.3
Over Delivery Sensitivity: 3600	BC_OVER_DEL_3600	37.7	24.9	7*	3.6	62.6	59.3
Over Delivery Sensitivity: 3200	BC_OVER_DEL_3200	38.1	24.5	7*	3.2	62.6	59.3
Warm Winter	BC_WARM	38.1	22.1	7.0	0.0	60.2	59.3
Over Delivery Sensitivity: 2800	BC_OVER_DEL_2800	38.5	24.1	7*	2.8	62.6	59.3
Over Delivery Sensitivity: 2400	BC_OVER_DEL_2400	38.9	23.7	7*	2.4	62.6	59.3
Leading the Way	LW	39.1	22.2	7.0	0.0	61.3	57.2
Over Delivery Sensitivity: 2000	BC_OVER_DEL_2000	39.3	23.3	7*	2.0	62.6	59.3
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	39.7	22.9	7*	1.6	62.6	59.3
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	40.1	22.5	7*	1.2	62.6	59.3
Low Demand	BC_LOW_DEMAND	40.2	21.2	7.0	0.0	61.4	58.1
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	40.5	22.1	7*	0.8	62.6	59.3
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	40.9	21.7	7*	0.4	62.6	59.3
Base Case	BC	41.3	21.3	7.0	0.0	62.6	59.3
Non Delivery Sensitivity: -400	BC_NON_DEL_400	41.7	20.9	7*	-0.4	62.6	59.3
System Transformation	ST	41.8	21.5	7.0	0.0	63.2	59.7
Consumer Transformation	CT	42.0	21.9	7.0	0.0	63.9	59.8
Non Delivery Sensitivity: -800	BC_NON_DEL_800	42.1	20.5	7*	-0.8	62.6	59.3
High Demand	BC_HIGH_DEMAND	42.4	21.3	7.0	0.0	63.7	60.5
Cold Winter	BC_COLD	42.5	20.8	7.0	0.0	63.3	59.3
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	42.5	20.1	7*	-1.2	62.6	59.3
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	42.9	19.7	7*	-1.6	62.6	59.3
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	43.3	19.3	7*	-2.0	62.6	59.3
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	43.7	18.9	7*	-2.4	62.6	59.3
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	44.1	18.5	7*	-2.8	62.6	59.3
Non Delivery Sensitivity: -3200	BC_NON_DEL_3200	44.5	18.1	7*	-3.2	62.6	59.3
Non Delivery Sensitivity: -3600	BC_NON_DEL_3600	44.9	17.7	7*	-3.6	62.6	59.3
Non Delivery Sensitivity: -4000	BC_NON_DEL_4000	45.3	17.3	7*	-4.0	62.6	59.3
Non Delivery Sensitivity: -4400	BC_NON_DEL_4400	45.7	16.9	7*	-4.4	62.6	59.3
Non Delivery Sensitivity: -4800	BC_NON_DEL_4800	46.1	16.5	7*	-4.8	62.6	59.3
Non Delivery Sensitivity: -5200	BC_NON_DEL_5200	46.5	16.1	7*	-5.2	62.6	59.3
Steady Progression	SP	46.5	20.0	6.5	0.0	66.5	63.3
Non Delivery Sensitivity: -5600	BC_NON_DEL_5600	46.9	15.7	7*	-5.6	62.6	59.3

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 2025/26 in the 2018/19, 2019/20, 2020/21, 2022/23, 2023/24 and 2024/25 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.

6.3 Recommended Capacity to Secure

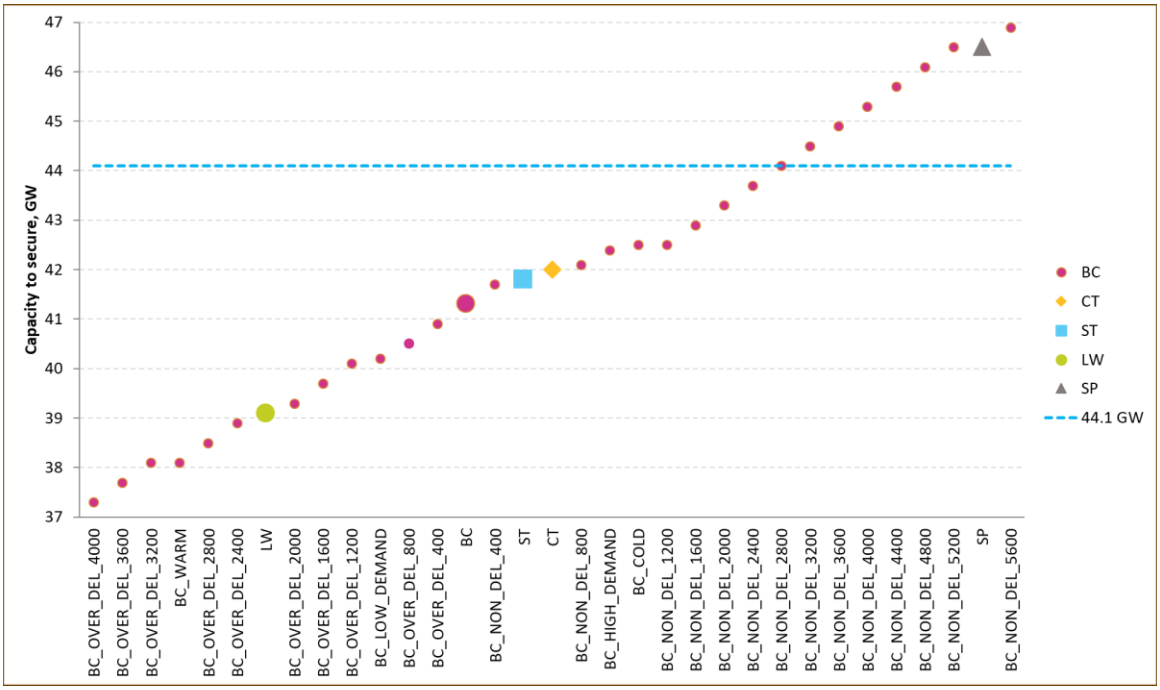
Table 33 shows there is a wide range in the capacity required to meet 3 hours LOLE from 37.3 GW to 46.9 GW. The 4 GW over-delivery and 5.6 GW non-delivery sensitivities define the extremes of the range. We use the Least Worst Regret (LWR) methodology described in Section 5.3 to select one of the values from Table 33 as our recommended target capacity for the 2025/26 T-4 auction).

The outcome of the LWR calculation is a capacity to secure of **44.1 GW**. This is the capacity associated with the 2.8 GW non-delivery sensitivity. This outcome excludes any capacity

[81] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Capacity%20Market%20Auction%20T4%20DY2024-25%20Final%20Report.pdf

secured for 2025/26 in earlier auctions assumed in the Base Case. Figure 25 illustrates the full range of potential capacity requirements and identifies the LWR outcome (44.1 GW).

Figure 25: Least Worst Regret recommended capacity to secure compared to individual scenario / sensitivity runs – 2025/26



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 was to occur in 2025/26 that is not covered, then the LOLE could be greater than 3 hours. This could mean mitigating actions (e.g. voltage reduction, max gen. service and emergency assistance from interconnectors) are deployed 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. The outcome of the LWR calculation covers 25 of the 33 cases as shown in Figure 25.

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 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. Although these providers are now eligible for CM agreements, if they opt out of prequalification and are assumed to be operational in 2025/26, an adjustment may still be required) – ***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 T-1 auction for 2025/26 – ***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.*

T-4 auction for 2025/26 could be:

- 44.1 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 44.1 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 T-4 for 2024/25 recommendation

In the 2020 ECR, we recommended a capacity to secure for 2024/25 of 41.6 GW which was 0.8 GW above the Base Case requirement of 40.8 GW. This recommendation assumed 6.3 GW of previously contracted capacity (net of 0.5 GW storage de-rating factor change). Our recommendation for the T-4 auction for 2025/26 is 2.5 GW higher than our recommendation for 2024/25 in the 2020 ECR. This is due to several increases totalling 4.6 GW that are offset by decreases totalling 2.1 GW.

The increases total 4.6 GW:

- A 1.8 GW increase due to a higher peak demand for 2025/26 compared to the 2020 Base Case peak demand for 2024/25 (due to higher industrial demand as a result of lower energy efficiency, and higher demand for electrification of heat and transport as a result of increased EV sales / lower efficiency and greater heat pumped demand / lower thermal efficiency – see Section 3.3 for more details).
- A 0.3 GW increase resulting from lower assumed opted-out or ineligible (below 1 MW) autogeneration.
- An increase of 0.5 GW due to additional non-delivery assumed in the Base Case (also including a small change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards)
- An increase of 2.0 GW resulting from an increased differential of the LWR outcome to the Base Case - the 0.8 GW non-delivery sensitivity set the LWR requirement in the 2020 ECR and the 2.8 GW non-delivery sensitivity in the 2021 ECR.

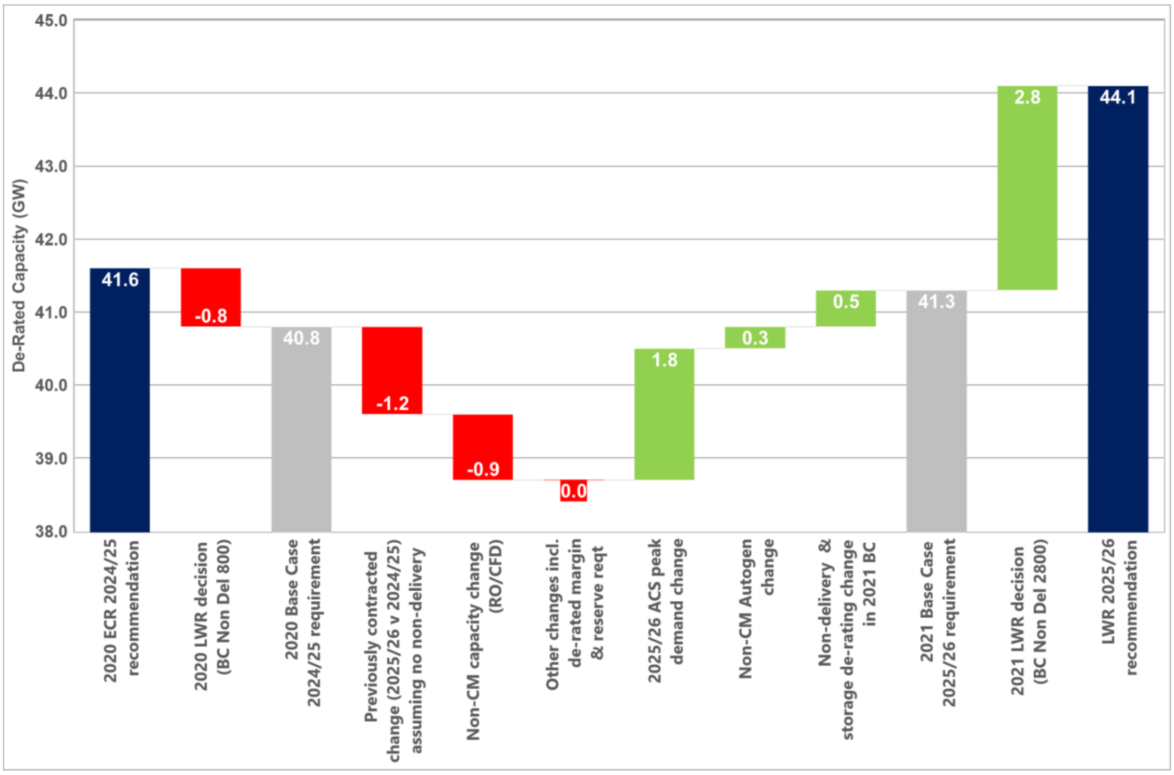
The decreases total 2.1 GW:

- A 1.2 GW net reduction due to an increase in previously contracted capacity arising from capacity awarded multi-year agreements in the 2024/25 T-4 auction (excluding the additional non-delivery assumed in the Base Case).
- A 0.9 GW decrease resulting from higher non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely the result of a higher offshore wind contribution at peak, together with a small increase in other small-scale capacity.
- A small decrease (<0.1 GW) due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2020 Base Case and rounding). Note that there was no change in reserve for largest infeed loss.

This analysis includes the risk of further non-delivery (up to a maximum of 5.6 GW in the most extreme non-delivery sensitivity). However, we note that if this non-delivery risk were to reduce, e.g. due to a change in market conditions or CM rules, this could result in a lower demand curve target recommendation in the T-1 auction, which will be reassessed in the 2024 ECR. We note also that the T-1 target capacity is subject to a minimum of half the original set-aside which could limit the size of any reduction.

The following waterfall chart, Figure 26, shows how the original 41.6 GW requirement for the T-4 auction for 2024/25 (derived from the 2020 Base Case 0.8 GW non-delivery sensitivity) has changed into a recommended requirement of 44.1 GW (derived from the 2021 Base Case 2.8 GW non-delivery sensitivity) as a result of the 2.5 GW net increase described above.

Figure 26: Comparison with recommended T-4 requirement for 2024/25 in 2020 ECR



Note: intermediate totals in grey above show requirements for 2020 Base Case and 2021 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 three of the scenarios modelled as a result of higher peak demands. For the other scenario, 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; a sensitive outcome is one that would change every time the included sensitivities changed. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in the table below.

Table 34: Sensitivity of LWR outcome (44.1 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-4.0 OD -3.6 OD -3.2 OD -Warm	-4.0 OD -3.6 OD -3.2 OD -2.8 OD -Warm	+4.4 OD	-5.6 ND	-5.6 ND -5.2 ND	+6.0 ND
2025/26 outcome (GW)	44.1	44.5	44.1	43.7	43.7	44.5

Removing the four lowest cases (4.0 GW OD, 3.6 GW OD, 3.2 GW OD and warm winter) had no impact on the outcome. Removing the next lowest case (2.8 GW OD) as well increased the outcome to 44.5 GW. Adding an additional over-delivery case (4.4 GW OD) did not change the original outcome (44.1 GW) Removing the highest case (5.6 GW ND) reduced the LWR tool outcome by 0.4 GW to 43.7 GW. Removing next highest case (5.2 GW ND) resulted in the same outcome (43.7 GW). Increasing the maximum non-delivery to 6.0 GW increased the original outcome by 0.4 GW to 44.5 GW.

Hence the outcome remains relatively stable to removing the lowest or highest sensitivities or adding additional OD and ND sensitivities.

Although the LWR outcome is relatively stable when the maximum non-delivery is removed or increased, we still believe the most robust maximum non-delivery sensitivity is 5.6 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 T-4 auction for delivery in 2020/21 there was a total of 4.9 GW of non-delivery observed up to the T-1 auction for 2020/21 (including capacity market units awarded multi-year contracts in the 2018/19 and 2019/20 T-4 auctions covering 2020/21). Since the T-1 auction for winter 2020/21, we estimate that observed additional non-delivery during the coldest part of the winter (early December to early February) exceeded 5 GW (see Section 3.10.4), representing capacity that was not available at all during this period and did not transfer its agreements via secondary trading. This capacity may be subject to penalties and/or termination depending on whether it has demonstrated requirements set out in the Capacity Market Rules.

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[82].
- **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.

[82] 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 used. 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:** The model used is 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.
- **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. Data from an innovation project (Development of GB Electric Vehicle Charging Trials)[83] has been used to inform 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. This gives 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.

The peak demand considered for the Base Case is the Average Cold Spell (ACS) demand. For winter 2020/21 it has been recognised that the current ACS methodology is not appropriate for use in a COVID-19 environment. For this reason, the calibration of peak ACS demand for 2020/21 has been undertaken by assuming no change to the five-year forecast from the Future Energy Scenarios 2020 for the underlying FES consumer demand.

[83] 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 Report, the FES Modelling Methods document or the FES Data workbook[84]. 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 35 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. Note the previous comments on the impact of COVID-19 on the ACS calculation for 2020/21.

Table 35: 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	46.4	45.1	-2.8%*	-1.3
2020/21	FES 2020	45.8*	44.7	-2.4%	-1.1

* ACS restricted National Demand for 2020/21 has been calculated using the FES20 forecast of underlying consumer demand for 2020/21 and the latest estimate of non-transmission generation. The latest estimate of non-transmission generation has changes by 1.1GW since FES20. Therefore, the table shows an error of 1.1GW for National Demand, wholly due to changes in estimates of non-transmission generation.

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.

[84] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

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[85] provides the starting point for the analysis of power stations which require access to the National Electricity Transmission System (NETS). It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted background provides the basis for the majority of the entries into the generation backgrounds, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also taken into account.

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

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

A.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?

[85] https://www.nationalgrideso.com/connections/registers-reports-and-guidance

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 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. For further details on this, please refer to FES Modelling Methods document[86].

A.3 EMR/Capacity Assessment Development Projects Matrix

Table 36 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 (with the exception of projects 19, 21 and 32 that were already in progress). Project 1 and Project 14 were not completed this year due to the reasons described in Section 2.5.2. Note that shaded projects either did not score high enough or were deprioritised and therefore were not progressed.

[86] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

Table 36: Development Projects Matrix

Development Project Description	Total*
1) Analysis of the sequential nature of the capacity procurement, taking account of the appropriate caution needed in relation to the quantifiable and unquantifiable uncertainties, risks and their consequent recourse costs. (PTE Recommendation 57)	15
2) Analysis of peak demand behaviour from the broad perspectives of current and future technical, society and regulatory evolution (PTE Recommendation 52)	14
3) As new data on embedded generators becomes available, consider specific de-rating factors for embedded plant types. (PTE Recommendation 53)	14
4) Improve data within BID3	14
5) Review how the impact of the COVID-19 pandemic on our supply and demand assumptions could change our target capacity recommendations	13
6) Improve the interconnector de-rating sensitivity formulation process.	13
7) Assessment of over-delivery for Base Case / sensitivities (PTE Recommendation 54)	12
8) Investigate and draw up plan for moving adequacy assessments from capacity assessment model into BID3 to be consistent with the European Resource Adequacy Assessment methodology	12
9) Review methodology for DSR de-rating factor	11
10) Review of assumptions and method that leads to the construction of the conventional distribution used in the LOLE calculation.	11
11) Investigate options to minimise any misalignment between the interconnection EFC calculated in DDM for the T-1 year and the previously contracted interconnection capacity	10
12) FES to DDM translation tool migration	10
13) List the modelling assumptions and limitations that might bias the interconnector ratings either up or down and comment on their materiality (PTE Recommendation 55)	8
14) The Technical Reliability of HVDC links should be considered more fully and whether the technical reliability of interconnectors and perhaps private links to large offshore wind farms, should become more explicitly (PTE Recommendation 56)	8
15) Develop an updated storage EFC proxy for CA model	7
16) Update and automate the Least Worst Regret Tool to take account of the outcome of the project addressing PTE recommendation 57	6.5
17) Carry out in depth review of ECR content	6
18) Improvements to the mechanics of the interconnector de-rating factor calculation process. This will include SQL and VBA code to automate processes that were previously carried out manually.	6
19) Update Capacity Assessment model translation tool to read Generation Background new format.	5
20) Review offshore wind power curves and consider creating large offshore power curve if additional data is available for large offshore wind turbines and there is a significant difference to the existing offshore power curve.	5
21) 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)	5
22) Improve historical demand time series for LOLE modelling (using Electralink data)	5
23) Consider duration-limits (if any) in the DSR and diesel generation technology types	4
24) Estimate the range of potential impact of non-delivery and over-delivery of non-CM (e.g. renewable) capacity in the Base Case.	3
25) Develop methodology for dealing with co-located facilities utilising model functionality developed in Phase 1 of project (carried out in 2019/20). Phase 2 of this project involves studies looking at different constrained hybrid site combinations (PTE Recommendation 51 Phase 2).	2
26) 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	2
27) Develop methodologies for calculating de-rating factors for new technologies that may enter the CM auctions	1
28) Build upon previous economic modelling of the viability of embedded generators to provide a more comprehensive view on potential embedded non-delivery. (PTE Recommendation 49)	1
29) Develop a proper demand time series shape for FES future security of supply modelling - at the moment we are using 2005-2017 demand time series shapes, but these are likely to be inadequate for > FES 2030 margins assessment work.	1
30) If the introduction of a large offshore wind power curve is justified, update models (CA model, DDM, UEM) to incorporate this new class.	1
31) Investigate the economic drivers of the DSR sector and distributional impacts of Ofgem's proposed changes to the charging regime. (PTE Recommendation 50).	0.5

Development Project Description	Total*
32) Support ENTSO-E working group developing a methodology to determine the maximum level of cross-border capacity that can participate in capacity mechanisms.	0
33) Develop a "net demand" version of the CA and DDM models, to avoid the use of an exogenous scalar applied to wind in the time collapsed calculations	0
34) Examine the advantages and risks of using historical data when determining interconnector de-rating factors. Provide and evaluate options on potential roles for historic evidence, alongside future-focused probabilistic modelling.	Not Scored
35) BEIS project request on small power generation and emissions	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 37 shows the annual demand while Table 38 shows the peak demand used for Base Case and the 4 FES scenarios 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 37: Annual Demand* by scenario

Annual Demand (TWh)	2022	2023	2024	2025	2026	2027	2028	2029
Base Case	296	296	297	298	301	293	296	302
Consumer Transformation	290	287	288	291	294	299	307	317
System Transformation	292	290	289	289	290	293	296	302
Leading the Way	285	281	280	283	287	294	303	316
Steady Progression	300	304	306	309	311	313	315	318

Annual Demand (TWh)	2030	2031	2032	2033	2034	2035	2036
Base Case	306	313	323	335	346	359	372
Consumer Transformation	329	347	369	395	418	437	456
System Transformation	306	313	323	335	346	359	372
Leading the Way	334	353	374	396	418	438	459
Steady Progression	322	327	334	340	348	355	364

*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 38: Peak Demand* by scenario

Peak Demand (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Base Case	58.0	58.0	58.2	58.5	59.3	60.3	61.1	62.2
Consumer Transformation	57.5	57.4	57.7	58.6	59.8	60.8	62.3	64.4
System Transformation	58.3	58.5	58.7	59.1	59.7	60.3	61.1	62.2
Leading the Way	56.0	55.0	55.1	55.9	57.2	58.5	60.4	62.6
Steady Progression	59.0	60.2	61.4	62.3	63.3	63.9	64.8	65.8

Peak Demand (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
Base Case	63.4	64.6	66.1	68.0	70.5	73.0	75.5
Consumer Transformation	66.9	69.2	71.8	75.0	77.9	80.7	82.9
System Transformation	63.4	64.6	66.1	68.0	70.5	73.0	75.5
Leading the Way	65.1	67.3	70.1	72.6	74.8	77.3	79.1
Steady Progression	67.0	68.0	69.3	71.0	72.9	74.7	76.5

*The definition of peak demand is unrestricted[87] GB National Demand plus demand supplied by distributed generation.

A.4.2 Generation Capacity Mix

Tables 39 to 43 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 39: Base Case generation capacity mix

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
CM eligible	65.1	64.3	67.2	69.0	59.6	60.7	65.9	65.7
Non-CM	34.7	36.3	36.6	38.6	44.5	46.2	48.5	51.8
Total peak capacity	99.8	100.5	103.7	107.6	104.0	106.9	114.4	117.5

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
CM eligible	68.8	68.1	70.9	73.9	74.8	73.5	72.8
Non-CM	57.1	64.8	64.4	70.5	76.9	86.0	93.3
Total peak capacity	125.8	132.9	135.3	144.4	151.7	159.5	166.1

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

Table 40: Consumer Transformation generation capacity mix

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
CM eligible	65.8	63.0	65.8	68.5	62.9	64.1	69.1	69.3
Non-CM	34.8	36.3	36.8	38.6	45.4	48.2	50.6	57.3
Total peak capacity	100.6	99.3	102.5	107.1	108.3	112.4	119.7	126.6

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
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 41: System Transformation generation capacity mix

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
CM eligible	65.1	63.3	66.3	68.4	60.0	61.2	65.9	66.2
Non-CM	34.7	36.3	36.6	38.6	44.5	46.2	48.5	51.8
Total peak capacity	99.8	99.6	102.8	107.0	104.5	107.4	114.3	118.0

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
CM eligible	67.9	68.0	70.9	74.6	74.6	73.3	72.7
Non-CM	57.1	64.8	64.4	70.5	77.1	86.2	93.5
Total peak capacity	125.0	132.8	135.3	145.2	151.7	159.5	166.2

Table 42: Leading the Way generation capacity mix

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
CM eligible	65.3	61.8	66.8	68.8	61.0	61.1	65.2	66.0
Non-CM	35.9	38.1	39.6	45.5	49.4	55.0	60.1	68.0
Total peak capacity	101.3	99.9	106.4	114.3	110.4	116.1	125.4	134.0

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
CM eligible	67.8	70.5	73.4	75.8	75.5	77.5	79.9
Non-CM	76.9	79.1	88.2	90.8	110.5	113.3	114.2
Total peak capacity	144.7	149.6	161.6	166.6	186.0	190.7	194.1

Table 43: Steady Progression generation capacity mix

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
CM eligible	64.2	63.7	66.3	66.7	65.0	65.7	71.4	73.0
Non-CM	33.5	35.2	35.8	35.4	35.2	36.2	36.4	42.7
Total peak capacity	97.6	98.9	102.2	102.2	100.2	101.9	107.8	115.6

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
CM eligible	71.4	75.2	78.8	81.9	84.6	85.8	88.3
Non-CM	48.2	54.0	52.1	52.5	53.7	55.9	61.4
Total peak capacity	119.7	129.2	130.9	134.4	138.3	141.7	149.7

Table 44 depicts the import capacity levels of interconnection for each scenario used for Base Case and the 4 FES scenarios covering the next 15 years.

Table 44: Import Capacity Levels for Interconnection (GW)

Capacity (GW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Base Case	5.66	8.4	9.8	9.8	9.8	9.8	14.5	14.5
Consumer Transformation	7.06	8.4	9.8	9.8	9.8	14.5	14.5	15.9
System Transformation	5.66	8.4	9.8	9.8	9.8	9.8	14.5	14.5
Leading the Way	7.06	8.4	9.8	9.8	13.1	14.5	18.65	18.65
Steady Progression	5.66	7.4	8.4	9.8	9.8	9.8	9.8	13.1

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
Base Case	15.9	15.9	15.9	15.9	16.65	16.65	16.65
Consumer Transformation	16.65	18.65	18.65	18.65	18.65	18.65	22.25
System Transformation	15.9	15.9	15.9	15.9	16.65	16.65	16.65
Leading the Way	18.65	21.55	21.55	21.55	26.75	26.75	26.75
Steady Progression	14.5	15.9	15.9	15.9	15.9	15.9	16.65

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 2026/27 onwards.

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

Capacity (GW)	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Base Case	48.2	48.4	48.3	48.3	49.6	51.0	50.4
Consumer Transformation	47.7	47.9	48.4	49.1	49.9	52.0	51.1
System Transformation	48.7	48.8	48.9	48.8	49.6	51.0	50.4
Leading the Way	45.2	45.1	45.2	46.2	46.6	46.9	47.5
Steady Progression	50.6	51.5	52.4	53.0	53.6	56.1	56.1
Minimum	45.2	45.1	45.2	45.2	46.2	46.9	46.9

Capacity (GW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
Base Case	50.0	48.9	50.2	50.8	50.6	50.0	48.5
Consumer Transformation	51.7	51.1	51.5	52.7	53.2	55.8	55.1
System Transformation	50.0	48.9	50.2	50.8	50.6	50.0	48.5
Leading the Way	48.0	48.2	49.2	50.5	51.2	53.5	54.6
Steady Progression	55.3	55.6	56.8	58.4	60.3	61.0	61.6
Minimum	46.4	45.2	46.4	46.7	46.5	45.8	44.1

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 2022/23 and 2025/26. The total capacity is lower than the nameplate capacity shown in A.4.2 since it is de-rated. The autogeneration in 2022/23 includes 0.4 GW assumed over-delivery (see 5.2). 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 2022/23 and 2025/26

Generation type	2022/23 Capacity (GW)	2025/26 Capacity (GW)
Onshore Wind	2.6	2.7
Offshore Wind	2.9	3.8
Biomass	4.0	4.1
Autogeneration	0.8	0.4
Hydro	0.9	1.0
Landfill	0.5	0.5
Other	1.5	1.8
Total	13.2	14.3

A.4.4 Station Availabilities

As with the previous three 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 low availability sensitivities apply lower values to three technologies: Coal, CCGT and Nuclear (existing) and the high availability sensitivities apply higher values to one technology: CCGT (see Section 3.10.2 for more details on these sensitivities). Table 47 shows values for these sensitivities in bold.

Table 47: Station availabilities by sensitivity

Technology type		2022/23	2025/26
CCGT	Low availability sensitivity	**88%**	**88%**
	Base Case	**91%**	**91%**
	High availability sensitivity	**93%**	**93%**
Nuclear (Existing)			
	Low availability sensitivity	**74%**	**74%**
	Base Case	**80%**	**80%**
	High availability sensitivity	**N/A**	**N/A**
Nuclear (New)		90%	90%
Coal	Low availability sensitivity	50%	50%
	Base Case	80%	80%
	High availability sensitivity	N/A	N/A
AD (including CHP)		70%	70%
Autogeneration		91%	91%
Biomass Dedicated/Conv./CCS/ CHP		89%	89%
EfW		89%	89%
EfW CHP		74%	74%
Gas CHP (large scale)		**As CCGT**	**As CCGT**
Gas CCS		**As CCGT**	**As CCGT**
Gas Turbine		95%	95%
Geothermal (including CHP)		89%	89%
Hydro		91%	91%
Landfill		59%	59%
Interconnection EFC^ (Base Case)		79%	80%
OCGT and Recip. Engines		95%	95%
Oil		95%	95%
Pumped storage*		95%	95%
Sewage Gas		49%	49%
Solar PV EFC		2%	3%
Tidal and Wave		22%	22%
Wind EFC (Base Case)		19%	17%

*See Section 4.1 for de-rating factors for duration limited storage.
^Interconnection EFC is only used in the calculation of de-rated capacity required to meet 3 hours LOLE. See Section 4.2 for more details on interconnected country de-rating factor ranges

A.4.4.1 Conventional Transmission Station Availabilities

Table 48 shows the station availabilities from each of the previous 7 winters for transmission-based generation as well as the average availability across this period.

Table 48: Station Availabilities

	Winter 2014/15	Winter 2015/16	Winter 2016/17	Winter 2017/18	Winter 2018/19	Winter 2019/20	Winter 2020/21	Average
Coal	86.86%	82.99%	91.05%	79.05%	81.61%	78.49%	60.69%	**80.11%**
Biomass	93.20%	94.43%	92.72%	77.45%	88.61%	86.38%	87.04%	**88.55%**
Gas	88.72%	90.60%	95.13%	89.58%	91.28%	89.42%	91.66%	**90.92%**
Hydro	92.66%	91.41%	89.94%	92.58%	87.31%	92.79%	91.40%	**91.15%**
Nuclear	88.28%	86.30%	84.75%	76.44%	77.17%	77.87%	72.25%	**80.44%**
Pumped Storage	92.79%	93.41%	96.69%	93.07%	94.34%	94.50%	97.50%	**94.61%**
OCGT	95.96%	94.99%	97.26%	97.23%	94.64%	94.95%	93.27%	**95.47%**

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. The reserve for response depends on a number of factors. This includes the largest loss on the system and the forecast demand[88]. Table 49 shows the reserve requirement to cover the largest in-feed loss[89] for each scenario. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held. Any other reserve held in addition to this (e.g. day ahead contingency) is assumed to be generating at real time if a stress event occurs; the only capacity assumed to be held back in reserve during a stress event is the reserve for largest loss.

Table 49: Reserve to cover largest infeed loss by scenario

In Feed Loss (MW)	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Base Case	1500	1500	1100	1100	1100	1100	2000	1900
Consumer Transformation	1500	1500	1100	1100	1100	1100	1900	1900
System Transformation	1500	1500	1100	1100	1100	1100	2000	1900
Leading the Way	1600	1600	1200	1200	1100	2000	1900	1900
Steady Progression	1500	1500	900	1000	1000	1000	1000	1900

In Feed Loss (MW)	29/30	30/31	31/32	32/33	33/34	34/35	35/36
Base Case	1900	1900	1800	1800	1700	1600	1500
Consumer Transformation	1800	1800	1700	1600	1600	1500	1500
System Transformation	1900	1900	1800	1800	1700	1600	1500
Leading the Way	1800	1800	1800	1800	1800	1800	1800
Steady Progression	1900	1900	1800	1800	1800	1700	1600

[88] See Annex 2 of https://www.elexon.co.uk/wp-content/uploads/2014/12/234_08a_Attachment_A_P305_Detailed-Assessment-v1.0.pdf
[89] 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[90].

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 13, Table 14 and Table 15 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 50, Table 51 and Table 52 provide further commentary on these values.

Table 50: Assumptions for 2022/23 T-1 non-delivery sensitivities

Category	Discrete (GW) *	Root sum of squares (GW) *	Notes
Large thermal	2.5	6.3	ECR 2018 reported a development project on non-delivery in response to PTE recommendation 31. 2.5 GW large thermal (coal and gas) considered at risk due to challenging economic outlook (lower than in the development project to reflect coal closures)
Nuclear	1.8	3.2	Two nuclear stations experienced extended outages covering winters 2018/19 to 2020/21 such that they weren't available at all.
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 would also cover risk of new-build projects being delayed.
Unproven DSR	0.4	0.2	Reflects risk that we have previously observed ~25% unproven DSR failing metering tests
Interconnectors	1.4	2.0	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 interconnector reliability (assumed 0.7 GW based on a single cable outage)
Sum of non-delivery	**6.8**	**3.5**	**Note: 3.6 = square root of (6.3 + 3.2 + 0.5 + 0.2 + 2.0)**
Market response	-1.5	-0.8	Based on non-delivery development project reported in 2018 ECR, which identified 1 GW CCGT (so net 1 GW large thermal) and over-delivery from interconnectors assuming 33% based on high de-rating factor range (based on outcome of development project in response to PTE recommendation 31). Market response for root sum of squares assumes same percentage as discrete case (i.e. 1.5 / 6.8 = 0.8 / 3.5)
Total	**5.2 (rounded down to nearest 0.4)**	**2.7**	

* All values rounded to nearest 0.1.

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

Table 51: Assumptions for 2025/26 T-4 non-delivery sensitivities

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. 2.0 GW large thermal (gas) considered at risk due to challenging economic outlook
Nuclear	1.8	3.2	Two nuclear stations experienced extended outages covering winters 2018/19 and 2019/20. As de-rating factors in 2025/26 do not 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 would also cover risk of new-build projects being delayed.
Unproven DSR	0.4	0.2	Reflects risk that we have previously observed ~25% unproven DSR failing metering tests
Interconnectors	2.5	6.3	Non-delivery based on combination of assuming interconnectors deliver in line with lower end of de-rating factor range (contributes around 1.8 GW) and interconnector reliability (assumed 0.7 GW based on a single cable outage)
Sum of non-delivery	**7.4**	**3.8**	**Note: 3.8 = square root of (4 + 3.2 + 0.5 + 0.2 + 6.3)**
Market response	-1.6	-0.8	Based on non-delivery development project reported in 2018 ECR, which identified 1 GW CCGT (so net 1.5 GW large thermal) and over-delivery from interconnectors assuming 33% based on high de-rating factor range (based on outcome of development project in response to PTE recommendation 31). Market response for root sum of squares assumes same percentage as discrete case (i.e. 1.6 / 7.4 = 0.8 / 3.8)
Total	**5.6 (rounded down to nearest 0.4)**	**2.9**	

* All values rounded to nearest 0.1.

Table 52: Assumptions for 2022/23 T-1 over-delivery sensitivities

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.
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	1.3	1.7	Assumes over-delivery in line with high de-rating factor range (5% reduction to reflect technical reliability)
Sum of non-delivery	**4.1**	**2.2**	**Note: 2.2 = square root of (1 + 2.3 + 0.1 + 1.7)**
Market response	-0.9	-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 GW from CCGT and response from interconnectors based on 33% from low de-rating factor range. 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. 0.9 / 4.1 = 0.5 / 2.2)
Total	**3.2**	**1.8**	

* All values rounded to nearest 0.1.

Table 53: Assumptions for 2025/26 T-4 over-delivery sensitivities

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 2025/26 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	2.2	4.8	Assumes over-delivery in line with high de-rating factor range (5% reduction to reflect technical reliability) plus an additional 0.6 GW representing a new project that could either deliver early or come online for the T-1 (e.g. IFA2 in winter 2020/21)
Sum of non-delivery	**5.0**	**2.9**	**Note: 2.9 = square root of (1 + 2.3 + 0.1 + 4.8)**
Market response	-1.2	-0.7	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 GW from CCGT and response from interconnectors based on 33% from low de-rating factor range. 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. 1.2 / 5 = 0.7 / 2.9)
Total	**3.8**	**2.2**	

* All values rounded to nearest 0.1.

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'[91], 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, 2019/20 and 2020/21 two nuclear plants failed to return to full service so maybe this is not as certain as previously thought as the nuclear fleet nears

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

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 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.

Adverse weather events (new for ECR 2021) – Our weather history is relatively short (< 15 years) and so won't include potential weather events that could occur in future. These may become more adverse due to climate change and will likely become increasingly important as the generation mix is increasingly dependent on wind / solar. At the moment, we don't have a credible data set. We have been supporting a project led by the National Infrastructure Commission and Met Office to develop credible adverse weather data sets that can be used by energy modellers. This will include weather scenarios that could have occurred but haven't. We expect these data sets to be available in Summer 2021 and the ESO will likely recommend a development project on this for 2021/22.

Non-delivery risks relating to environmental legislation and carbon pricing – It is possible that changes to environmental legislation and carbon pricing could impact the running hours and profitability of thermal stations and subsequently increase the risk of non-delivery. While we model non-delivery risk, we have not explicitly modelled risks due to environmental legislation or carbon pricing. The scenarios in the FES consider different generation mixes that would cover some of this uncertainty (e.g. different diesel closure profiles). In addition, since the modelling is targeting 3 hours LOLE, we are only interested in a very small portion of the year, which may not be significantly impacted by running hour restrictions. Should we identify specific risks relating to non-delivery due to either of these factors, then we could consider including within the existing non-delivery sensitivities.

A.6 Storage De-rating Factor Data Assumptions

As reported in Sections 2.4.3 and 4.1, we have calculated the de-rating factors for duration limited storage in the 2021 ECR based on an updated view of storage durations and capacities (see table below).

Please note that given that this work was carried out before the Base Case storage capacity figures were finalised, the capacities in the table may differ slightly from the final published values. In 2017, we ran an industry consultation[92] 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 2021 ECR Base Case for the penetration of storage by capacity and duration are listed in the table 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 94.61% this year.
- The histogram of stress event durations of the same Base Case (see Figure 27 and Figure 28), 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 de-rating factor equivalent to the product of the incremental EFC and the technical availability of the storage class overall i.e. namely (EFC)*(TA-PS).

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

Table 54: Base Case duration limited storage assumptions (near final)

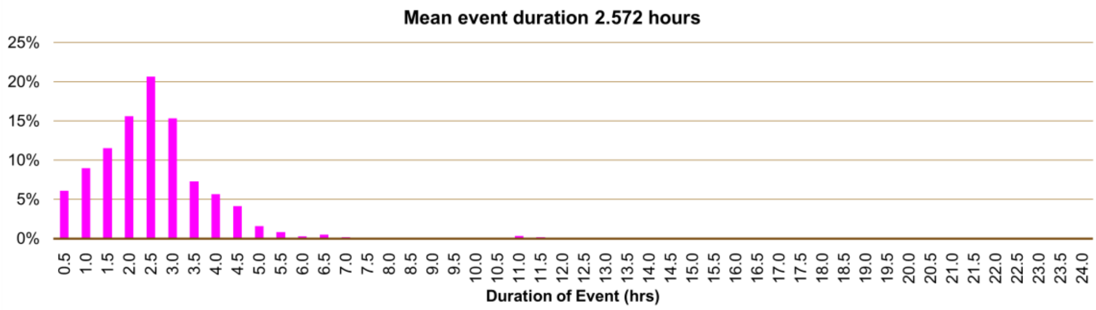
Duration Category (Hours)	2022/23 T-1 Capacity (MW)	2025/26 T-4 Capacity (MW)
0.5	544	594
1	983	2,102
1.5	87	87
2	43	184
3	5	5
4	4	4
6	1,731	2005
20+	740	740
Total	**4,136**	**5,720**

This year, there is lower level of storage capacity in the 2021 ECR Base Case than in the 2020 ECR Base Case in the T-1 year (even though the T-1 years have advanced by one) and an increase in storage capacity (particularly short-duration storage) in the T-4 year. This change reflects updated market information e.g. storage units awarded capacity market agreements in recent auctions.

Our renewables de-rating consultation[93] showed (slide 22) that solar capacity also has an impact on storage incremental EFCs, with large increases in solar capacity resulting in modest increases in storage EFCs. However, this impact is small compared to the impact of increases in short-duration storage capacity that reduces the storage incremental EFCs.

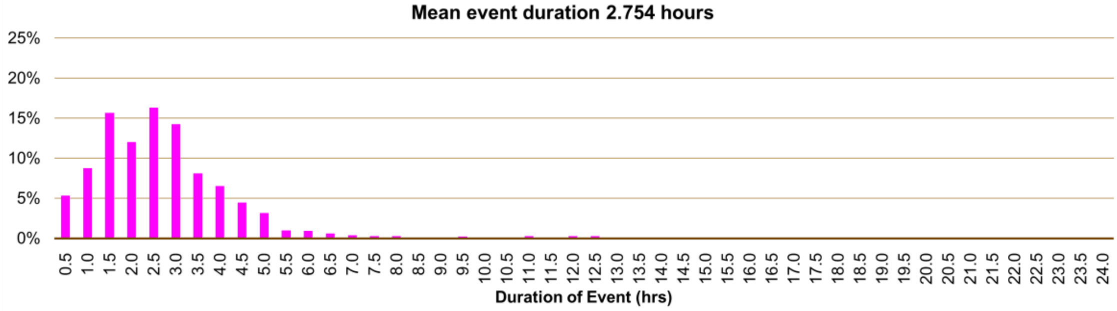
Due to the lower storage capacity, the de-rating factors in Table 18 have increased since the 2020 ECR for the T-1 year. In addition, the duration threshold corresponding to 95% of stress events has reduced from 5 hours to 4.5 hours in the T-1 year. Conversely, the de-rating factors for the T-4 year have reduced and the duration threshold corresponding to 95% of stress events has increased from 5 hours to 5.5 hours in the T-4 year due to the increase in storage capacity, particularly short-duration storage of 1 hour or less. This shows that for cases adjusted to 3 hours LOLE, those with higher proportions of short-duration storage have a higher proportion of longer duration stress events. The distribution of stress events[94] in the T-1 and T-4 years is illustrated in Figure 27 and Figure 28.

Figure 27: Stress Event Duration Histogram for 2022/23 T-1 Base Case at 3 hours LOLE



[93] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20-%20De-Rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf
[94] 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 28: Stress Event Duration Histogram for 2025/26 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[95].

A.8 ECR Recommendations and CM Auction Summary

Table 55 summaries the ECR recommendations, recommended demand curve target adjustments after prequalification, Secretary of State (SoS)'s decisions, capacity secured[96] (all in MW) and clearing prices (in £/kW) by auction.

Table 55: 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	N/A	300	2,100	2,400	2,400	2,252	£ 45.00
T-3 22/23	45,400	1,200	44,200	-200	44,000	44,000	45,059	£ 6.44
T-1 22/23	4,500							
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	400	41,200	500	41,700	40,100[97]	40,820	£ 18.00
T-4 25/26	44,100							

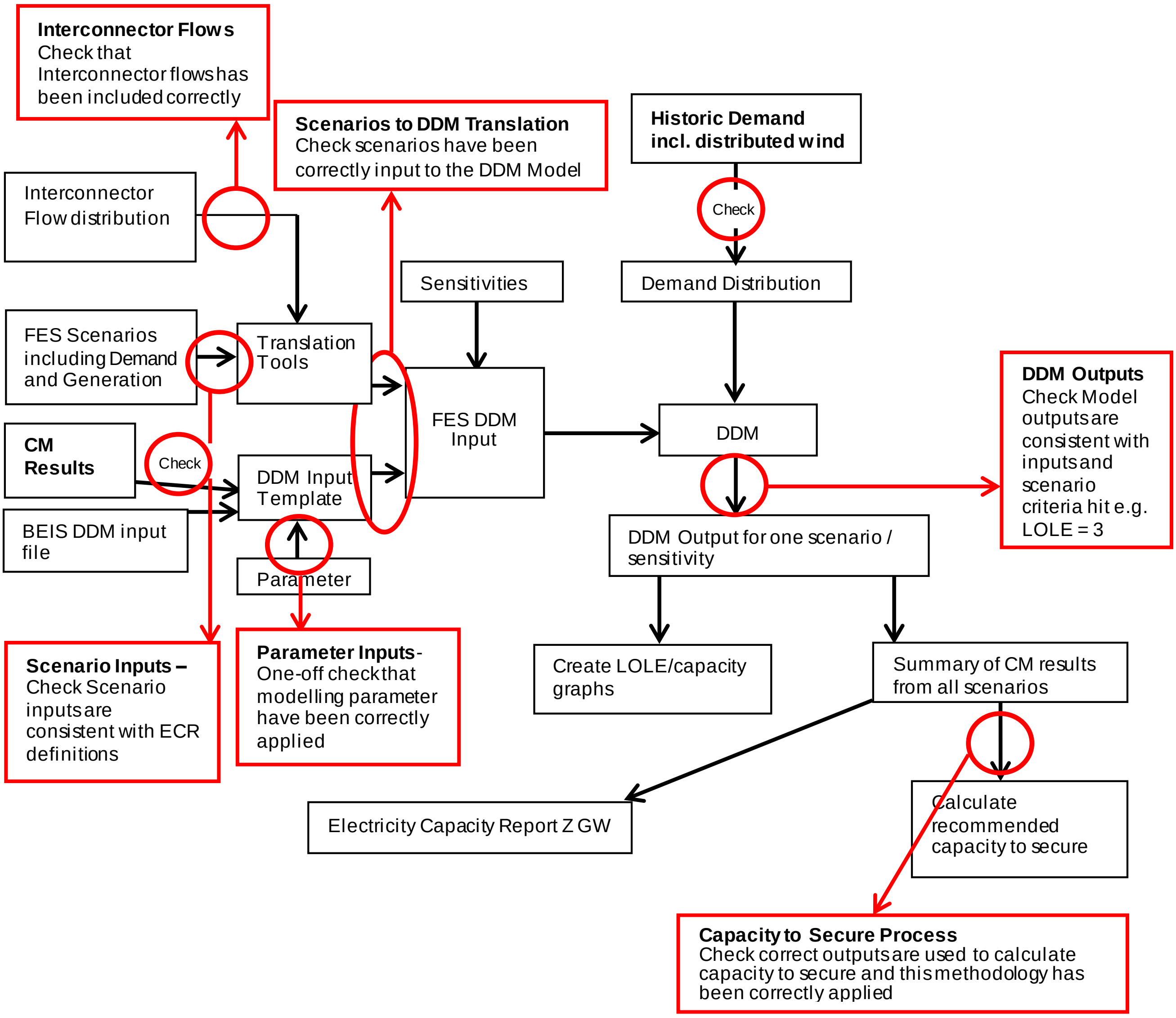
[95] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf
[96] Note that the capacity secured in the auction shown above may not be the same as the total secured capacity reported in the latest CM registers (e.g. due to terminations or metering tests for unproven DSR etc.)
[97] Energy minister accepted T-4 recommendation but increased set aside for T-1 from 400 MW to 2,000 MW

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[98]. 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 into 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 29: QA Checks Process Diagram for each Target Year



98 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[99], 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 man ager level. The Assumption and outputs will be published in the annual FES document on week commencing 12 July 2021.

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 an 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.

[99] https://www.nationalgrideso.com/document/187746/download

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[100]), 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.

[100] https://www.lcp.uk.com

A.10 Interconnector Modelling Assumptions

In response to PTE recommendation 55 the assumptions used in BID3 for interconnector de-rating factor calculation and a commentary on the materiality of these assumptions has been produced.

A.10.1 BID3 Assumptions

The data in Table 56 gives a high-level overview of some of the assumptions made in BID3. This covers both input data and modelling assumptions. Note that these assumptions only cover those used in the Security of Supply and LOLE modules within BID3 (these are the modules used in calculating the interconnector de-rating factors).

Table 56: BID3 Modelling Assumptions

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
GB plant capacity	NGESO Future Energy Scenarios	By unit for transmission and larger embedded. Aggregated for smaller embedded	
Europe plant capacity	Afry Central scenario	By unit for transmission, aggregated for embedded	
Plant capacity is net capacity	NGESO FES/Afry	N/A	Modelling uses net output instead of gross output
GB annual demand	NGESO FES	Annual TWh figure	Flexible demand is currently ignored by BID3, this will become increasingly important in the future
Europe annual demand	Afry Central scenario	Annual TWh figure	Flexible demand is currently ignored by BID3, this will become increasingly important in the future
Thermal plant availability profiles	Afry	Mostly monthly or monthly business day/non-business day. Some quarterly or weekly	
Renewable plant output profiles	Afry	Mostly hourly, some hourly by month pre-2006	Reduced resolution pre-2006, currently data from 1985 – 2018 is used
Storage plant availability profiles	Afry	Monthly	Some new storage types have little or no historic data
Hydro plant availability profiles	Afry	Weekly	Only has data for a limited number of weather years, uses a default otherwise
GB – Europe interconnector capacity	NGESO FES	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
Europe – Europe interconnector capacity	Afry Central scenario	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling
Interconnector loss rates	Afry	By interconnector (variable by direction if desired)	
GB demand profiles	Afry	Annual historic hourly, split by demand type	Data for 1985 – 2018 currently used
Europe demand profiles	Afry	Annual historic hourly, split by demand type	Data for 1985 – 2018 currently used
Short-term storage parameters	Afry	By unit	Includes MWh capacity and round-trip efficiency
Flows from non-modelled markets	NGESO/Afry	Hourly	Currently assumed to be zero (float)
LOLE module looks for tightest hours	Afry	N/A	LOLE module may model hours outside the delivery period if they are amongst the tightest 102 hours
Generation (after interconnector losses are considered) is always cheaper than load loss	Afry	N/A	BID3 modules used do not use economic data
Most markets are modelled as a single node (with no internal transmission constraints)	Afry	N/A	Currently Denmark, Italy, Norway and Sweden are modelled as more than one market

A.10.2 Markets Modelled

Table 57 shows the markets that are modelled in BID3. If a market does not appear in the table then it is not modelled at all and any interconnection that may exist between a modelled and non-modelled market is assumed to be at float at all times.

Table 57: Markets Modelled in BID3

Country	Number of Markets Modelled	Notes
Austria	1	
Belgium	1	
Czechia	1	
Denmark	3	Includes Kriegers Flak offshore wind as a separate market
France	1	Does not include Corsica

Country	Number of Markets Modelled	Notes
Finland	1	
Germany	2	Includes Kriegers Flak offshore wind as a separate market
United Kingdom	1	Models the GB market
Ireland	1	Republic of Ireland and Northern Ireland modelled as a single market
Italy	9	
Luxembourg	2	
Netherlands	1	
Norway	5	
Poland	1	
Portugal	1	
Slovakia	1	
Slovenia	1	
Spain	1	Mainland only modelled
Sweden	4	
Switzerland	1	

A.10.3 Materiality Commentary

This section is a commentary on the some of the assumptions made in BID3 and where possible the materiality to the interconnector de-rating factor calculation process. The commentary is mostly hypothesis and conjecture as it has not been thoroughly tested in BID3. However, it is included in this document to give an indication of the thought processes used by NGESO when calculating interconnector de-rating factors. We welcome any feedback on our thoughts or if you think that there are factors that we may not have appreciated fully.

Markets modelled – The current modelling includes all remote markets that are forecast to be connected to GB and also at least every market connected to the remote markets. The dataset currently used allows more markets to be modelled but this has significant implications on both the computational resource and time required to run the analysis. It is assumed that no power flows in either direction on the interconnectors between modelled and non-modelled markets. A potential compromise is to use fixed flows on these interconnectors.

Interconnectors – The AC interconnectors are not modelled with as much detail as the DC interconnectors. This is primarily an issue with the difficulty of selecting a single value for parameters, such as capacity and losses, for AC interconnectors when compared to DC interconnectors. Some testing has been carried out by NGESO varying AC interconnector losses which demonstrates that the interconnector de-rating factors are not very sensitivity to changes in this parameter.

Random outages – The current version of BID3 only models random outages for discrete thermal units (i.e. not including small aggregated units). Historic average availabilities are used to create a deterministic percentage for all other generator types (intermittent renewable, storage, hydro and aggregated thermal units). The dataset used does not have enough information in it to discretise most of the generator types to allow random outages to be used. Therefore, further data and modifications to BID3 would be required to extend the random outage methodology to other generator types. There would also be a penalty in terms of the computational resource required as the complexity of the modelling would be increased.

Station demand – The capacity that appears in the scenarios is net capacity of the unit (i.e. gross capacity minus station demand). When a unit has randomly been determined to be on forced outage then it is assumed that the capacity of the unit is zero. For a number of technology types this is not correct as there will be residual station demand after a trip. This is not currently modelled in BID3 and therefore may over-estimate the capacity available in a market.

Plant availability profiles – The availability profiles in BID3 are based upon historic availability data. This may not be accurate for a number of reasons. Firstly, unit availability may change in the future (for example as a unit comes towards the end of its' operating life). Secondly, there are new unit designs (e.g. EPR nuclear reactors) and new technologies (e.g. compressed air storage) for which there is very little or no historic availability data to work from. Thirdly, there may be some issues when a unit first commissions (this may be even more prevalent where the unit is the first of a kind) that alters the availability in the early period of operation. Using historic data is probably the best option available and therefore an unavoidable assumption in BID3.

Internal transmission constraints – Excepting those countries that are modelled as more than one market in Table 57, no internal transmission constraints are modelled in BID3. Each market is modelled as a node. It is assumed that power can flow through a market without constraint from one interconnector to the next. Clearly this is a simplification, but it is made to make sourcing data easier and reduce the computational effort required. The risk of an internal constraint being present increases as the number of markets through which the power must flow increases.

Demand types – BID3 allows for different types of demand, which allows for different demand profiles. This is useful to model new trends in demand such as heat pumps or electric vehicles. At present there is not much data on how these new demand types may be profiled throughout the year. A limitation of the module used in BID3 is that it ignores flexible demand types. This is not a problem for pure demand as it can be assumed that flexible demand will not be present during times of system stress. However, the limitation also excludes demand types that can discharge back into the grid, such as in vehicle-to-grid, this will become more of a problem in the future as this technology becomes more widespread. At present we believe that this limitation does not materially affect the interconnector de-rating factors but is likely to in the future and we will look to work with the developers to allow all demand types to be modelled fully.

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