ESO
Electricity Capacity Report

(Submitted to the Department for Energy Security and Net Zero)

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

31 May 2023

ESO

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1 Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling undertaken by the 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 2024/25 and 2027/28.

The Government requires the 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.

The ESO has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2022 process. This led to the ESO undertaking steps to improve this year's analysis. In addition, there has been continued engagement with the Department for Energy Security and Net Zero (DESNZ), the PTE and the Office of Gas and Electricity Markets (Ofgem) throughout the process to enable them to scrutinise the modelling approach and assumptions used.

Chapter 2 of this report describes stakeholder engagement. Chapter 3 describes the modelling approach, including the tools used and enhancements made, for this year's analysis. Chapter 4 covers the scenarios and sensitivities modelled. Chapter 5 details the de-rating factors for generating technologies, storage, demand side response (DSR) and interconnected countries. Chapter 6 and Chapter 7 contain modelling results and the recommended capacity to secure for the T-1 auction for delivery in 2024/25 and T-4 auction for delivery in 2027/28, respectively. Finally, the Annexes contain 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. In addition to this year's report, we have also published a Data Workbook[3] that contains the data behind the numerical tables and charts in the ECR.

Russia's illegal invasion of Ukraine continues to impact global energy markets. Our recommendations in this report assume that there continues to be sufficient available gas supply for gas-fired power generation, and that electricity interconnectors respond to market signals. We continue to monitor the impact of Russia's illegal invasion of Ukraine on both global and UK markets, working closely with Government, Ofgem and National Gas Transmission.

We recommend capacities to secure for the T-1 and T-4 CM auctions to meet the GB reliability standard of 3 hours loss of load expectation (LOLE) for a credible range of risks and uncertainties. This can lead to an outcome where the Base Case LOLE is lower than 3 hours per year. We consider this to be appropriate and means that when we get to the Delivery Year[4], we will have a margin that provides sufficient resilience to credible risks and uncertainties, and means that the Reliability Standard should still be met, even if these credible risks and uncertainties materialise.

[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/1091801/panel-technical-experts-2022-report.pdf

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

[4] For example, see the ESO's Winter Outlook Report https://www.nationalgrideso.com/research-and-publications/winter-outlook

1.1 Results and Recommendations

Table 1 shows ESO's recommendations for the target capacity for the 2023 auctions: T-1 delivering for 2024/25 and T-4 for 2027/28. Some adjustments may be required to set the final target capacity for each auction following prequalification; this is described in Chapters 6 and 7. 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 2024/25 and 2027/28 for the T-1 and T-4 Capacity Market auctions

	2024/25 T-1	2027/28 T-4
Recommended target capacity	7.4 GW	44.5 GW

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

The scenarios we have modelled are listed as follows:

- Base Case[5] (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Falling Short (FS)

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 4.8 describes each sensitivity and how it has been modelled.

The recommendation for the target capacity to secure is informed by a cost-optimised method called Least Worst Regret (LWR). LWR 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 Cost of New Entry (CONE) and an energy unserved cost (referred to as the Value of Lost Load (VoLL)) of

[5] The Base Case (BC) is based on the FES Five Year Forecast to 2027/28, then aligned to System Transformation from 2028/29 onwards to provide a full 15-year view.

£17,000/MWh[6]. This is consistent with a Reliability Standard of 3 hours LOLE[7]. 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 2024/25 T-1 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for the T-1 auction for delivery in 2024/25 of **7.4 GW**, which is 0.4 GW above the Base Case requirement. 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 2024/25 from earlier T-3 and T-4 auctions that is assumed in the Base Case.

For the case ahead of the 2024/25 winter where no future unknown non-delivery has yet materialised (similar to the ESO's Winter Outlook Reports[8]), this recommendation corresponds to a Base Case LOLE of 0.3 hours/year and a de-rated margin of 3.8 GW (6.3%), while if the 3 GW of future unknown non-delivery were to materialise then by the 2024/25 delivery year the Base Case LOLE would be 2.4 hours/year[9].

When compared to the analysis for 2024/25 in the 2020 ECR, our recommendation is 5.4 GW higher than the 2.0 GW originally set aside by the Secretary of State for the T-1 auction (see section 6.3.3 for details):

- Non-delivery is the largest category of increase, accounting for 3.9 GW of increase when comparing the 2020 ECR T-4 Base Case with the 2023 T-4 ECR Base, there is an 0.8 GW in known non-delivery and a 3.1 GW increase in future unknown non-delivery (see section 4.8.4).
- Changes to scenario assumptions account for approximately 2.6 GW of increase, particularly the increase to peak demand (1.0 GW), lower embedded RO/CFD capacity due to improved data sources (0.9 GW), and higher reserve and response for largest loss (0.7GW)as a result of updating our calculation to reflect the new reserve and response products (see section 3.4.2).
- The remaining changes comprise 1.1GW net decrease including contracted vs de-rated TEC (0.4 GW increase), a change in the LWR outcome (0.4 GW decrease), demand curve target change (0.5 GW decrease), higher auction procurement due to low clearing price (0.7GW decrease), and de-rated margin changes (0.1 GW increase)

Figure 1 shows how the original 2.0 GW set aside for the T-1 auction for delivery in 2024/25 (derived from the 2020 Base Case 0.8 GW non-delivery sensitivity) has changed into a LWR outcome of 7.4 GW (corresponding to 0.4 GW above the Base Case requirement) as a result of the net increase described above.

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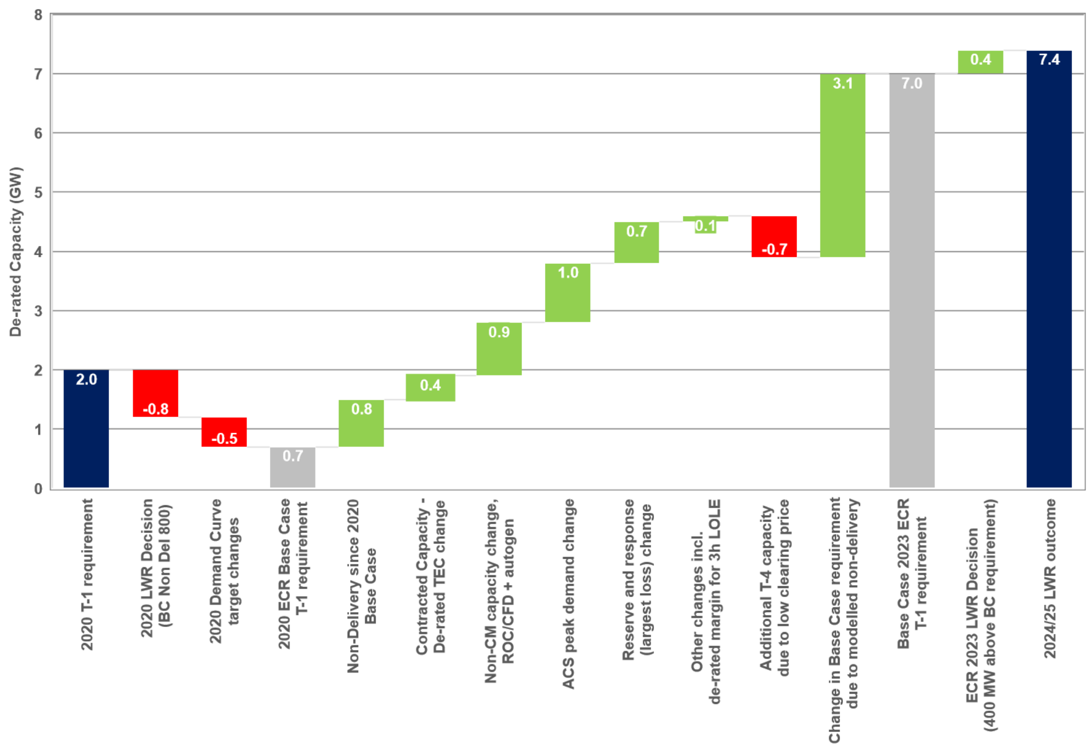
[6] Note that the Government's Reliability Standard was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT). For more information, see: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

[7]The Reliability Standard of 3 hours LOLE is given by the ratio of net CONE / VoLL.

[8] https://www.nationalgrideso.com/research-and-publications/winter-outlook

[9] The de-rated margin assuming 3.1 GW future unknown non-delivery materialises for 2024/25 would be 2.1 GW / 3.5%

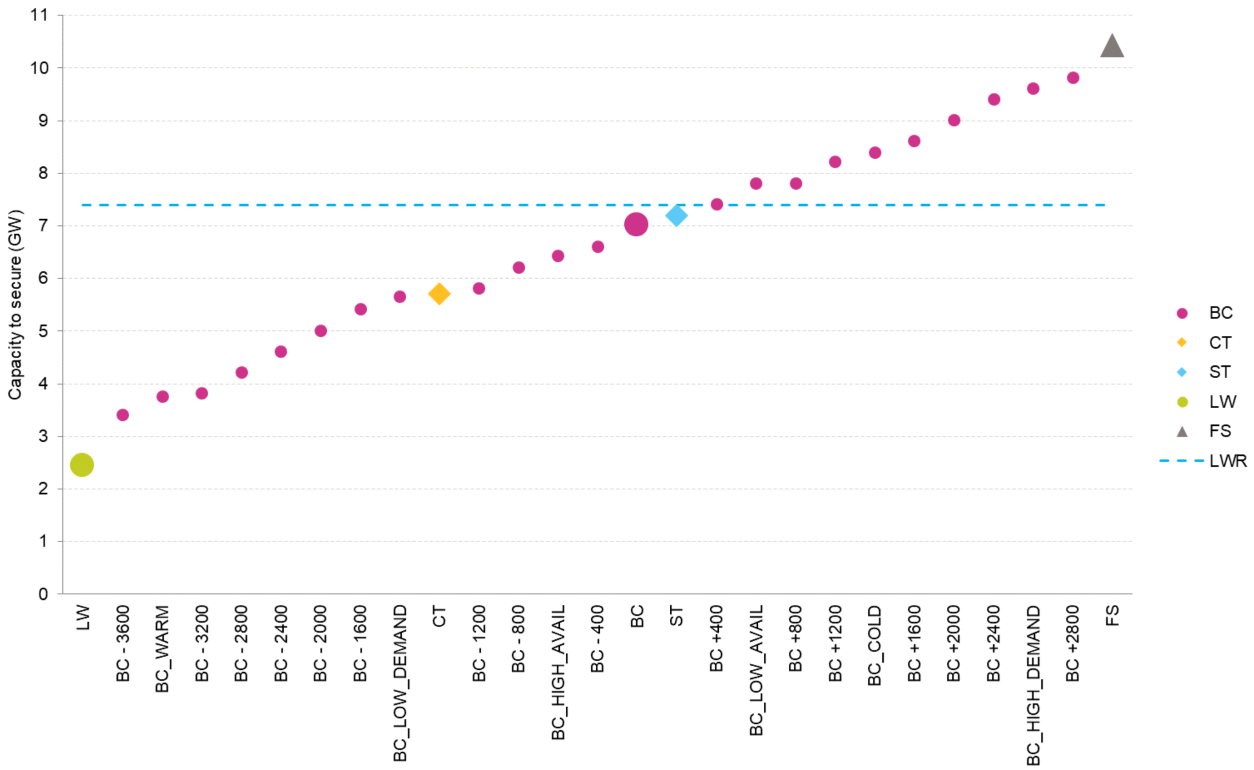
Figure 1: Comparison with original 2024/25 T-1 requirement (de-rated)



Note: intermediate totals in grey above show requirements for 2020 Base Case and 2023 Base Case

Figure 2 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 7.4 GW derived from the LWR outcome.

Figure 2: LWR outcome and other cases modelled comparison – 2024/25



1.1.2 2027/28 T-4 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for T-4 auction for delivery in 2027/28 of **44.5 GW,** which is 0.8 GW above the Base Case requirement. Our Base Case assumes no new nuclear units in 2027/28 and assumes that biomass conversion units are eligible to participate in the capacity auction in 2027/28 following the end of RO/CFD support. 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 2027/28 via earlier T-3 and T-4 auctions that is assumed in the Base Case.

For the case ahead of the 2027/28 winter where no future unknown non-delivery has yet materialised (similar to the ESO's Winter Outlook Reports[10]), this recommendation corresponds to a Base Case LOLE of 0.3 hours/year and a de-rated margin of 4.4 GW or 7.1%, while if around 3 GW of future unknown non-delivery were to materialise then by the 2027/28 delivery year the Base Case LOLE would be 2.0 hours/year[11].

When compared to the T-4 analysis for 2026/27 in the 2022 ECR, the 2023 ECR recommendation for 2027/28 is 0.6 GW higher. This net difference is the result of 7.9 GW of increases offset by 7.3 GW of decreases since the 2022 ECR (see section 7.3.3 for details):

- 3.1 GW increase due to future unknown non-delivery (see section 4.8.4)
- 2.3 GW increase due to lower non-CM capacity, largely as biomass conversion come off RO / CFD support and become CM eligible
- 3.2 GW decrease due to increase in previously contracted CM capacity (esp. new build CCGT and battery storage)
- 2.4 GW decrease due to a change in the LWR outcome
- 0.8 GW net increase due to remaining changes including change in contracted storage / wind EFC (0.9 GW decrease), changes in peak demand (0.4 GW increase) and reserve and response for largest loss (0.4 GW increase), and other changes including de-rated margin for 3 hours LOLE/yr and rounding (0.9 GW increase).

Figure 3 shows how the original 43.9 GW requirement for delivery in 2026/27 from the T-4 auction (derived from the 2022 Base Case 3.2 GW non-delivery sensitivity) has changed into a recommendation of 44.5 GW as a result of the 0.6 GW net decrease described above.

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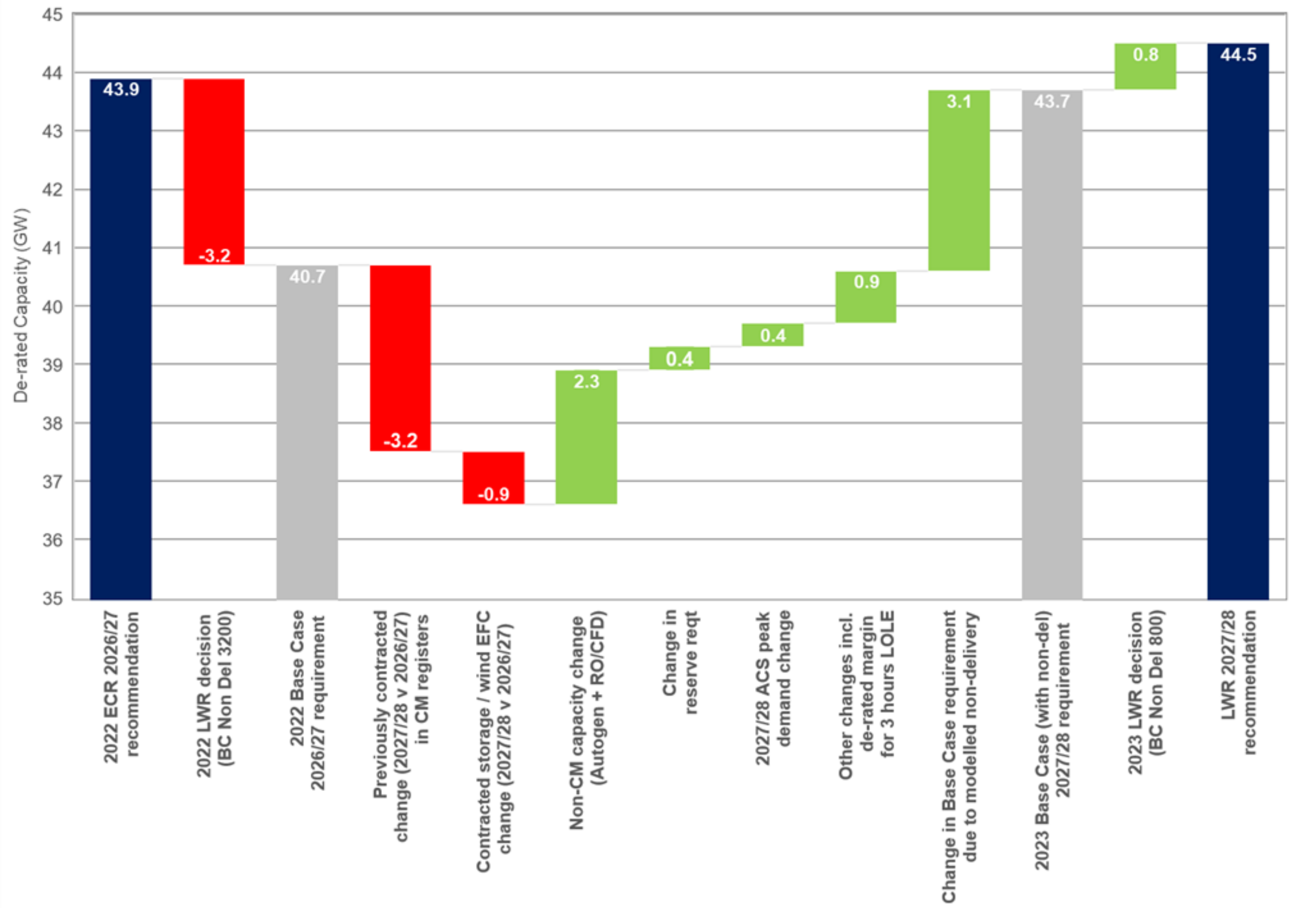
[10] https://www.nationalgrideso.com/research-and-publications/winter-outlook

[11] The de-rated margin assuming around 3 GW future unknown non-delivery materialises for 2027/28 would be 2.5 GW / 4.0%

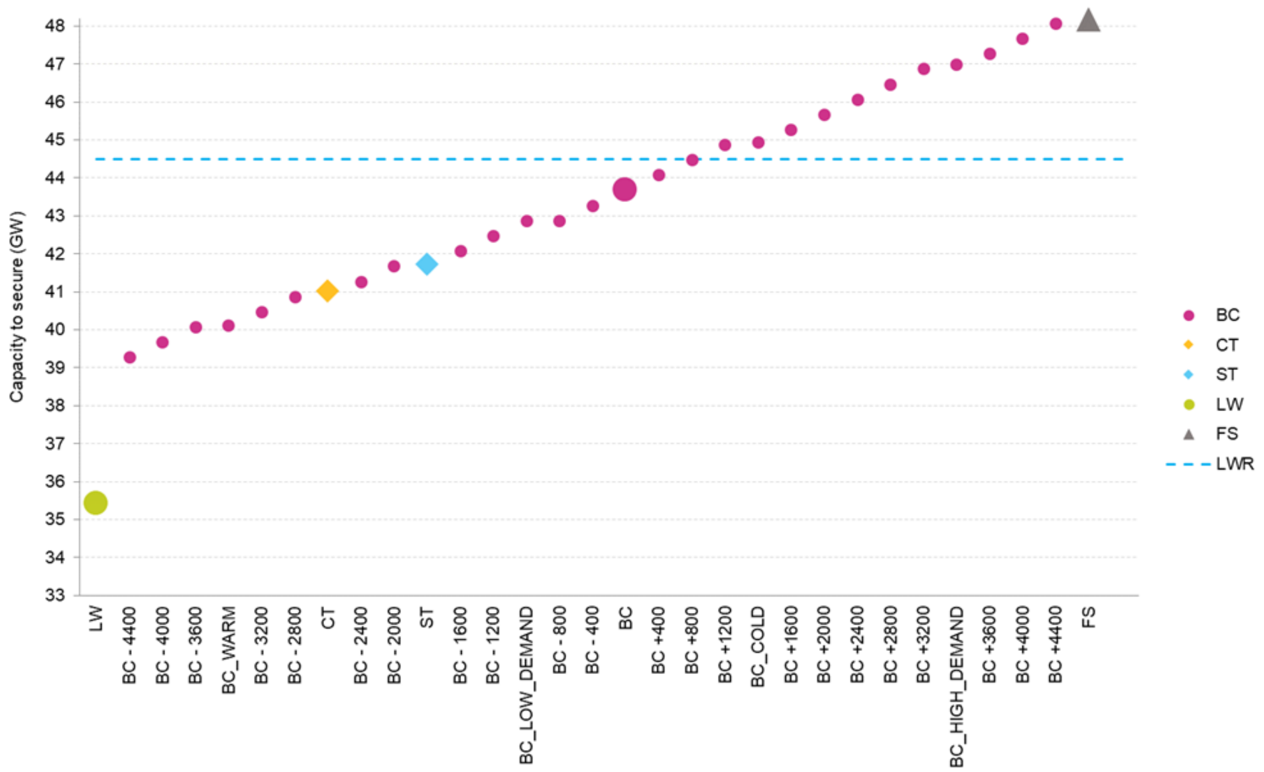
Figure 3: Comparison with recommended 2026/27 T-4 requirement in 2022 ECR



Note: intermediate totals in grey above show requirements for 2022 Base Case and 2023 Base Case

The chart in Figure 4 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 44.5 GW derived from the LWR outcome.

Figure 4: LWR outcome and other cases modelled comparison – 2027/28



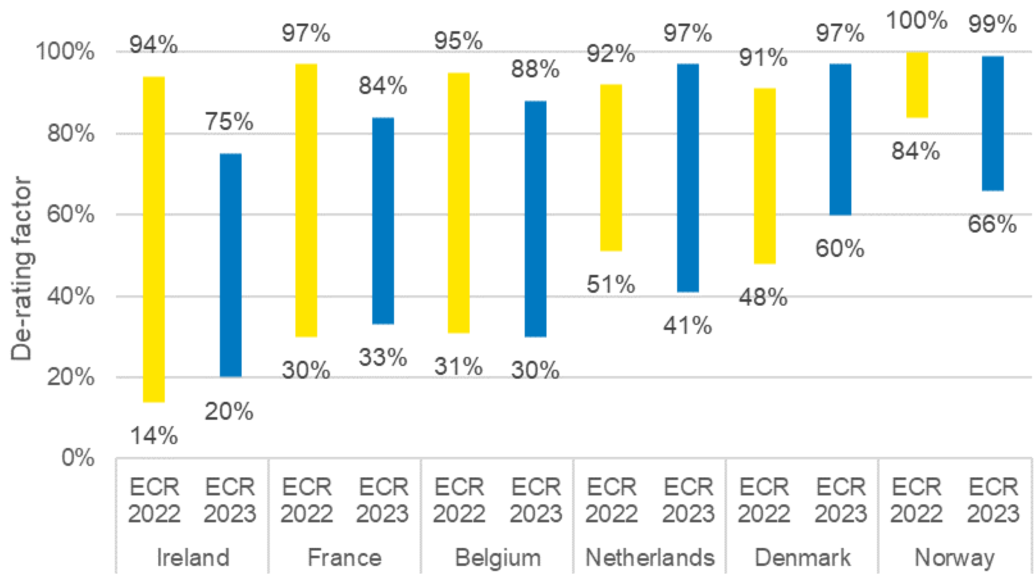
1.2 Interconnected Countries De-rating Factor Ranges

Figure 5 shows the de-rating factor ranges for interconnected countries based on the modelling we have done using our pan-European market model, PLEXOS. These cover existing and potential future interconnected countries. These ranges inform the choice of de-rating factors for the T-4 auction for delivery in 2027/28, which are ultimately decided by the Secretary of State in consultation with the PTE. The ranges indicate that there is uncertainty in the European outlook, and while we consider this to be appropriately reflected in our modelling, it highlights the challenge in assigning a single de-rating factor value for each individual interconnector to participate in the auction. We have not provided de-rating factor ranges for the T-1 auction as all interconnectors that we expect to be operational for the start of the delivery year have already been awarded agreements in the T-4 auction for delivery in 2024/25.

In this year's modelling, we have continued to use the same method since the 2020 ECR 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 5.2. This approach is also more consistent with work that has been undertaken by the European Network of Transmission System Operators (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[12].

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain or for technical reliability. Adjustments for technical reliability are determined by DESNZ. While the interconnector de-rating factors are based on the combination of resource availability in neighbouring markets and technical reliability, it is expected that all interconnectors, that are successful in the Capacity Market auction will deliver in line with the obligations associated with their agreements, as is the expectation from any other capacity provider.

Figure 5: Modelled de-rating factor ranges for interconnected countries



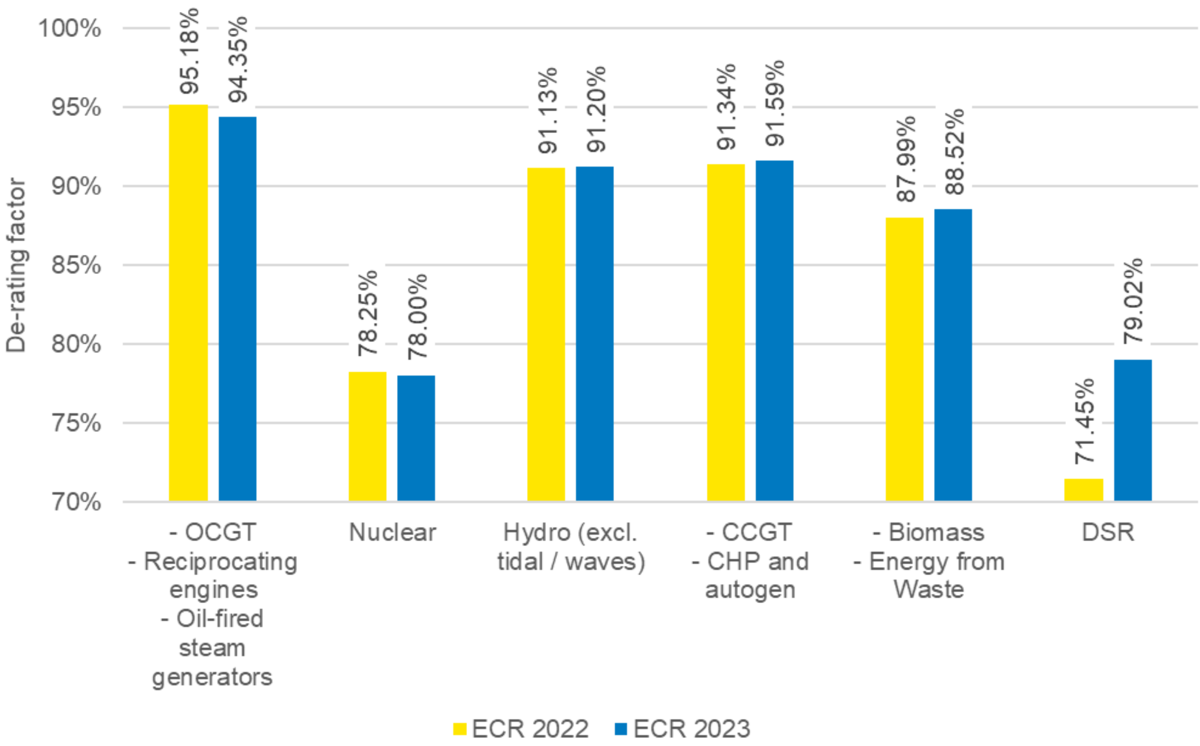
Note: ECR 2022 refers to 2026/27 T-4 values and ECR 2023 refers to 2027/28 T-4 values.

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

Figures 6-10 show the de-rating factors for conventional plants, storage and renewables. De-rating factors from the previous year's report 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 5 and tabular versions of the results are found in the companion ECR Data Workbook.

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

Figure 6: De-rating factors for conventional plants and DSR



Note: Conventional plant de-rating factors apply to both the 2024/25 T-1 and 2027/28 T-4 auctions. See Annex A.5.6 Conventional Plant Types for descriptions of each technology class.

Figure 7: De-rating factors for duration limited storage T-1 comparison

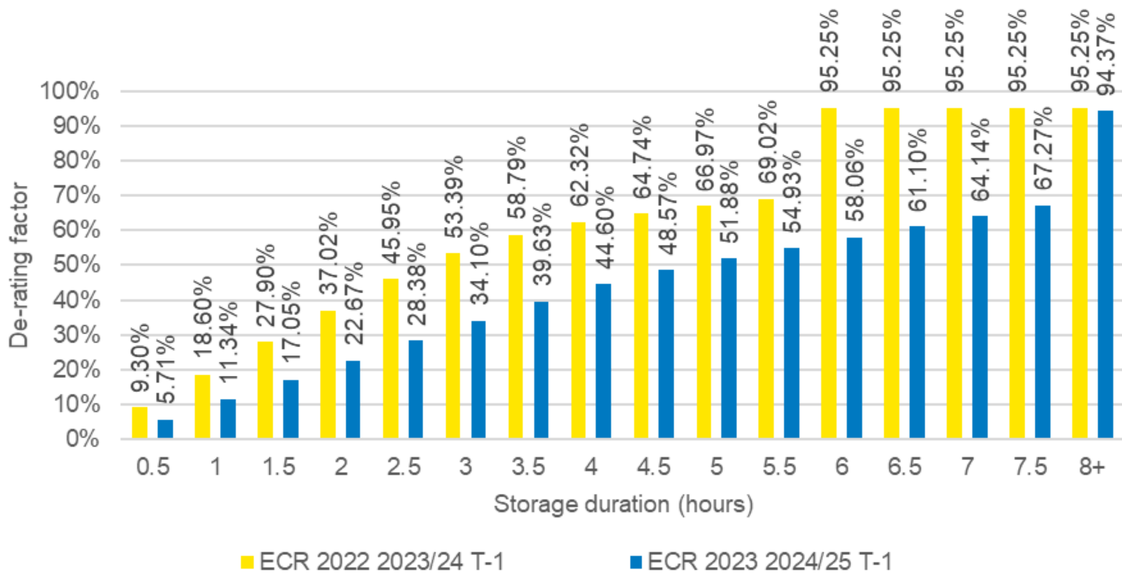


Figure 8: De-rating factors for duration limited storage T-4 comparison

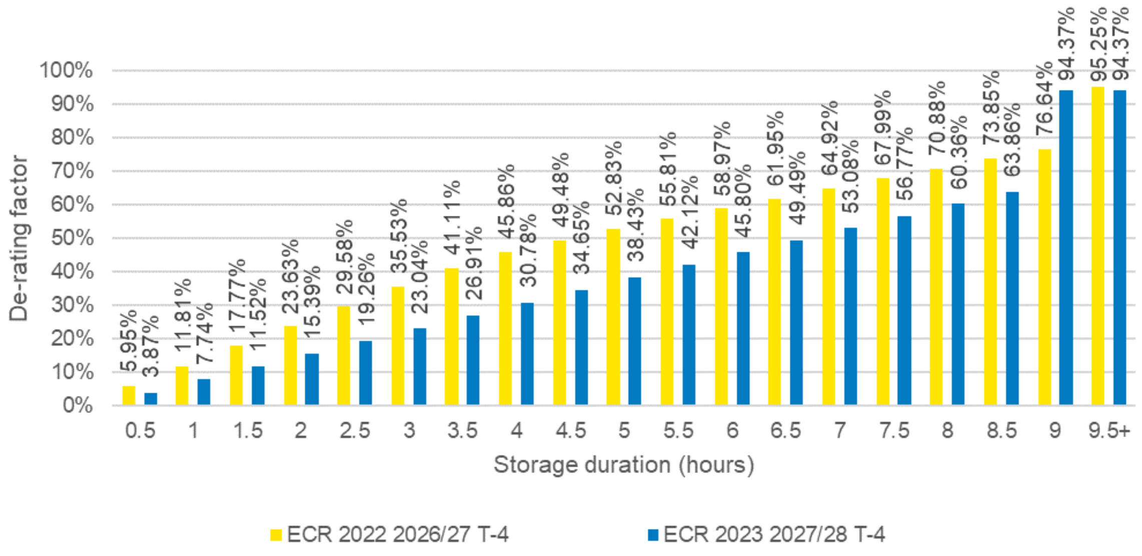


Figure 9: De-rating factors for renewables T-1 comparison

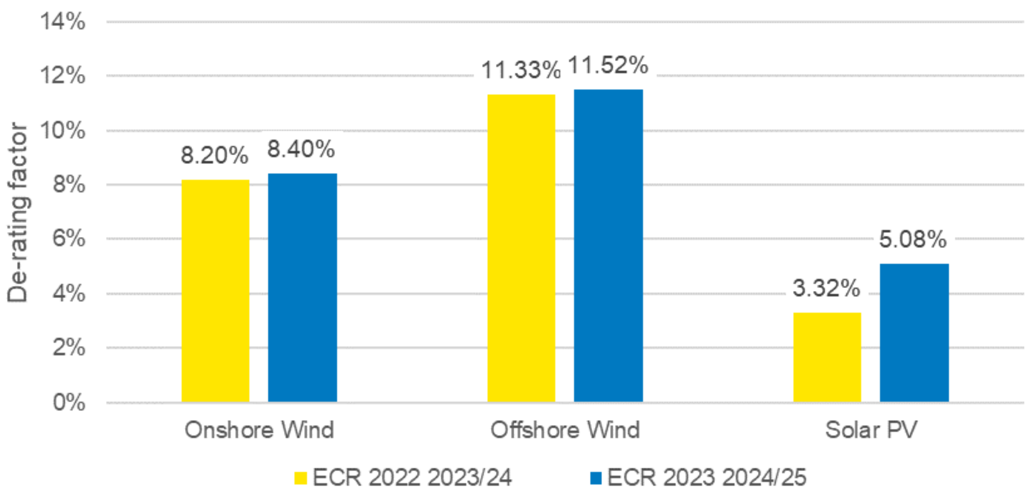
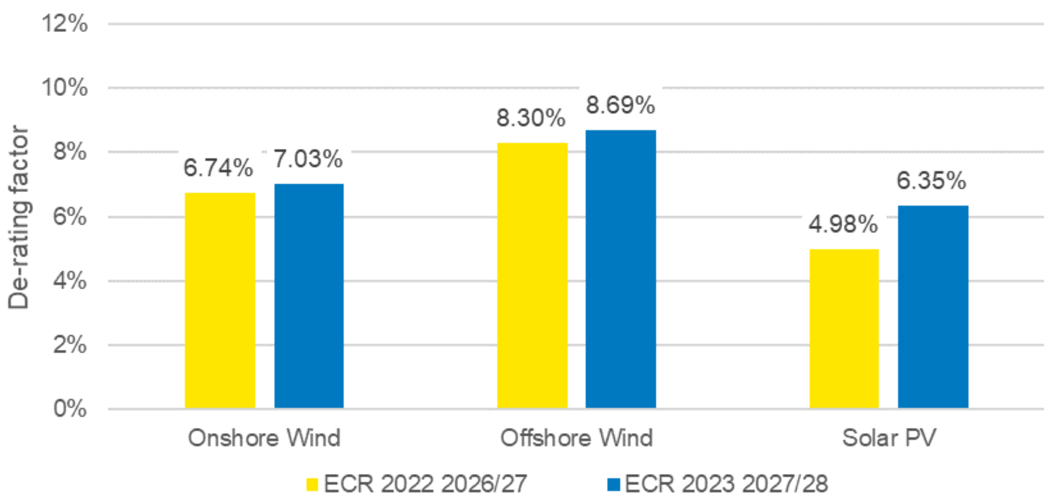


Figure 10: De-rating factors for renewables T-4 comparison



This year, there is a higher level of duration-limited storage capacity in the 2023 ECR Base Case than in the 2022 ECR Base Case particularly for the T-4 year (see Annex A.7 for more details). As a result of this increased capacity, the duration threshold corresponding to 95% of stress events has increased from 6 hours to 8 hours in the T-1 year, which combined with lower incremental Equivalent Firm Capacity (EFCs) also due to the increased duration-limited capacity, has resulted in step changes in the de-rating factors for this year. Solar PV de-rating factors have also increased as the increased short-duration storage capacity shifts the distribution of stress events towards longer events that start earlier in the day (when there is some solar output). Further explanation of historical trends and our de-rating methodology for storage and renewables can be found in our briefing note[13].

[13] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Storage%20and%20Renewables%20De-rating%20Factors%20Briefing%20Note%202023.pdf

2 Stakeholder Engagement

The modelling analysis has been undertaken by the ESO and has included regular engagement with DESNZ, Ofgem and DESNZ's PTE throughout the whole process. This extends from agreeing the joint priorities of development projects through to scrutinising the modelling that underpins the ESO's recommendations in the ECR before it is submitted to DESNZ by 1 June.

The ESO have also engaged with other industry stakeholders in its role as EMR Delivery Body and in its role of developing the FES assumptions that underpin the modelling. Our stakeholder engagement in our role as EMR Delivery Body includes the annual Capacity Market Launch Event and bilateral meetings. It also includes industry consultations on changes to the methodologies used to calculate technology de-rating factors. We have also continued to produce the interconnector modelling briefing note, which provides an early view of how we intend to carry out the interconnector modelling. It also provides all industry stakeholders an opportunity to provide feedback directly to the PTE for consideration in scrutinising our modelling and their subsequent recommendations.

The 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. We use this information to help to shape the content of the FES resulting in a set of holistic, credible and plausible scenarios. We publish the FES Stakeholder Feedback Document each year to demonstrate how we have used this feedback to inform our scenarios.

The ESO strives to improve the FES consultation process each year by enhancing engagement activities and finding better ways to record and analyse stakeholder feedback. In developing FES 2023, we engaged with 1516 stakeholders across all our events from 364 different organisations. Of these organisations, 236 were new for 2023. This broad engagement continues to cover our nine stakeholder categories. The range of organisations we heard from covers local authorities, universities, distribution networks, government bodies, flexibility providers, consumer charities and interconnectors. The 2023 Stakeholder Feedback Document14 describes the key changes to this year's scenarios which are expected to be published in the FES 2023 document on 10 July 2023.

We continue to welcome engagement with our stakeholders on our modelling either through email (emrmodelling@nationalgrideso.com), industry forums or bilateral meetings.

[14] https://www.nationalgrideso.com/document/277071/download

3 The Modelling Approach

3.1 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)[15]?

We continue to use the Dynamic Dispatch Model (DDM)[16] to answer this question. This maintains consistency with the energy market modelling work undertaken by DESNZ. The DDM has the functionality to model the Capacity Market and produces the same output LOLE values as ESO's capacity assessment model, when given the same inputs. This 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)[17] 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 4. 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' is the demand that includes all peak demand in Great Britain, not just that on the transmission system. 'Unrestricted' demand means that no Demand Side Response (DSR) 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 the 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 4.8.

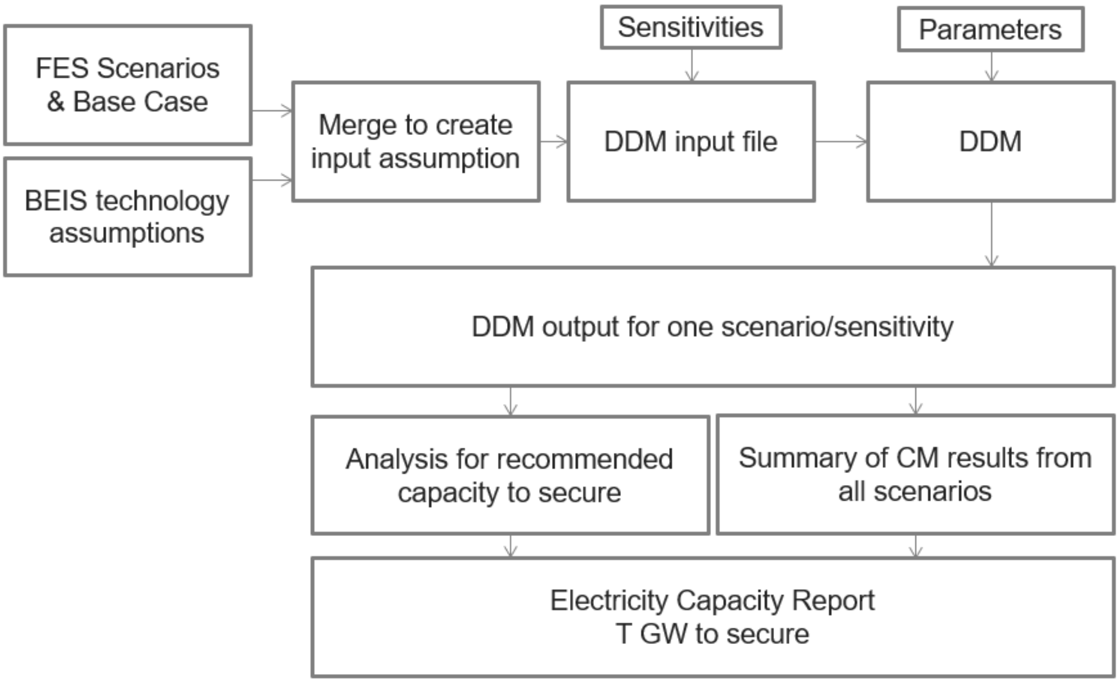
Figure 11 shows our modelling process. We model a 15-year horizon in the DDM that extends to 2037/38. The modelling process determines both the capacity to secure and the capacity expected to be delivered outside of the Capacity Market for each scenario and sensitivity modelled. The capacity to secure for each of these cases is then considered together to produce a recommended capacity to secure for delivery in 2024/25 T-1 and T-4 for delivery in 2027/28. Further details describing this can be found in Annex A.6.

[15] 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.

[16] DDM Release 6.1.90.0 was used for this analysis

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

Figure 11: Process flow chart of approach to calculate target capacity to secure (T) from individual scenario/sensitivity runs



3.2 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 CM auction

C. De-rated non-eligible capacity expected to be delivered outside the CM 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.5 and A.6.

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 CM auction for years 2024/25 and 2027/28. These values are used in the LWR calculation to produce the recommended target capacity (T) for each auction. Further details can be found in Chapters 6 and 7.

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

3.3 High Level Modelling Assumptions

In addition to the Base Case and scenario assumptions described in Chapter 4, the DDM also requires some additional modelling assumptions for the simulations to run. These include assumptions relating to demand, generation, interconnectors and station availability. Further details on these assumptions are explained in this section.

3.3.1 Demand and Generation

The demand and generation assumptions are based on those used in modelling by DESNZ[18] (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 in 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 CM
  - Capacity outside the CM (including capacity secured via previous auctions)
  - Capacities of existing and new interconnectors
- Station availabilities and de-rating factors by technology

The data for these assumptions is provided in Annex A.5.

3.3.2 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 4.7.

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 was updated in a recent development project to reflect the outputs from the 2022 ECR pan-European market modelling (see 3.4.2 for more details) 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. This 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.5.4..

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.

[18] https://www.gov.uk/government/collections/energy-generation-cost-projections

The interconnection EFC does not impact the T-4 capacity requirement since no interconnectors have been previously contracted.

In addition to this modelling work, the ESO provides modelled ranges of de-rating factors for each connected country participating in the CM auction. See Chapter 5 for more detail around this process and the modelled de-rating factors ranges for each country.

3.3.3 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. The ESO calculates the expected availability for each generation type based on its performance during the winter peak period over the last seven years[19]. 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[20].

The data for the station availability assumptions is provided in Section 5 (CM eligible conventional generation) and Annex A.5.4 (CM ineligible and EFCs for interconnectors, storage, solar and wind).

Intermittent renewable generation

Intermittent renewable plants such as wind and solar are assumed to run whenever they have an available source of energy (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 historical 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 is calculated by the DDM and is therefore an output of our modelling. For a system with a LOLE of 0.1-0.5 hours per year there are less periods where wind generation is preventing loss of load and the wind EFC is lower than it would be in a system with a LOLE of 3 hours per year. This is often true of our Base Case after the T-1 auction has taken place and before any future unknown non-delivery risks materialise. This has a LOLE typically <1 hour per year and has a reduced wind EFC assuming the recommended capacity is secured (see Annex A.5.4 for Base Case Wind EFCs at 3 hours LOLE).

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

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[19] 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

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

DDM is calculated this way using updated estimates (see Annex A.5.4). Please refer to Section 2.5.2 in the 2019 ECR for further details on these projects[21].

We 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[22]. 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 LWR 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.

3.4 Development projects

We undertake development projects each year to enhance the ECR modelling. The development projects are intended to address recommendations from the PTE in their annual report and any other areas where the modelling could be improved. This also includes updating/refreshing existing data sources, integrating the latest versions of the models, and improving efficiency in our modelling processes. The development projects taken forward each year are selected from a prioritisation process involving ESO, DESNZ, the PTE and Ofgem. The ESO then delivers the development projects between September and February, which includes regular engagement with DESNZ, 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.

3.4.1 Process for selecting which development projects to progress

The prioritisation for the 2022/23 development projects followed the same process as last year. Each project was ranked independently by ESO, DESNZ and Ofgem 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.

[21] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

[22] 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

3.4.2 Key projects undertaken

In their 2022 report[23], the PTE made eight new recommendations numbered 66 to 73, summarised in Table 2.

Table 2: New PTE recommendations - project summary

#	Summary	Outcome
66	Demand Uncertainty Project	Described below
67	Demand Price Elasticity	Described below
68	To consider if the capacity of facilities providing ancillary services is being accounted for properly in the resource adequacy calculation	Described below
69	Impact of network infrastructure constraints on the reliability standards	Described below
70	To consider the use of operational data for estimating wind derating factors	Not progressed this year
71	To consider the use of operational data for estimating battery derating factors	Described below
72	To expand the statistical analysis of ICDRFs to fully understand the implication of bimodal distributions	Not progressed this year
73	Review of reliability standards and its implementation	This recommendation does not relate to modelling and needs to be considered by DESNZ and Ofgem.

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 (PTE 66 and 67)

The Base Case peak demand forecast is one of the most important assumptions that impacts the recommended auction targets. As such there has been a lot of focus on this in recent years, reflected in recommendations from the PTE in their annual reports and the enhancements we have made to improve this area of our modelling. This is a complex area of modelling that is continually evolving. We have engaged regularly with the PTE and DESNZ on this during the last year and expect to implement further enhancements in the coming years to address previous PTE recommendations, including recommendations 66 and 67 in the 2022 PTE report.

This year we have developed our work to assess the uncertainty around the Base Case peak demand at sector level in response to recommendation 66 in the 2022 PTE report. In this analysis we have added sector level uncertainties to our Monte Carlo Model of losses and metered demand. This led to improved interpretation of uncertainty through elicitation of model owner expertise for heat, transport, industrial & commercial peak demand. As part of ongoing improvements, we have

[23] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1091801/panel-technical-experts-2022-report.pdf

also developed probability distributions for each sector model. This is fed into a Monte Carlo model to develop sector and total demand uncertainties. We believe that this represents a positive step in trying to better quantify this uncertainty and will allow us to build on this in the coming years. As such, we have decided to model the high / low demand sensitivities based on this uncertainty.

Modelling non-delivery probabilistically (PTE 60 phase 2)

In our DDM modelling we account for known non-delivery risks i.e. units with Capacity Market (CM) agreements that are known to be unable to meet their CM obligations in the auction target years. We have also used non-delivery sensitivities to model the risk of future unknown non-delivery (for example due to early closures, unplanned outages over the whole winter, delays / cancellations of new capacity etc.) that was not known at the time of the modelling. In the 2022 ECR, the maximum future unknown non-delivery level in these sensitivities was derived from summing different types of non-delivery and allowing for a potential market response, and was informed by analysis of historic non-delivery and when it became known to us.

In their 2021 report, the PTE recommended (No. 60) a review of our approach to modelling future (unknown) non-delivery risks in the ECR. In Phase 1 of this project, which is described in the 2022 ECR, our academic consultants recommended that we should model modest levels of future non-delivery (similar to an average of historical levels) by multiplying the station availabilities currently used in the LOLE calculation by (1 – an average non-delivery probability).

In Phase 2 of the project carried out for the 2023 ECR, we have updated our view of historic non-delivery and when it became known to us (see Table 6) and commissioned LCP Delta to implement the recommendation to model non-delivery probabilistically in the DDM. We have also tested the impacts of those changes on the capacity to secure modelling for the 2022 ECR Base Case for different non-delivery probabilities using the new DDM functionality.

Based on our testing, we have decided to utilise this new functionality in the 2023 ECR by applying a 6% average non-delivery probability to CM-eligible capacity (except wind and interconnection) in all DDM runs which gives an increase in the capacity to secure to meet 3 hours LOLE of around 3 GW. This increase is similar to the average non-delivery in the most recent 5 delivery years that occurred after the final T-1 target had been set following prequalification.

We have continued to model non-delivery (and over-delivery) sensitivities (with 0.4 GW increments) away from the Base Case in the 2023 ECR to provide granularity in the Least Worst Regret (LWR) calculation so it can select a value at or near the optimum. However, we have only included non-delivery sensitivities that fall within the range of the other scenarios and sensitivities modelled to avoid any non-delivery sensitivity influencing the LWR outcome by having the highest requirement.

Review of the DDM GB interconnection fleet distributions

In the DDM, we model the contribution of the GB fleet of interconnectors in stress events for each scenario and delivery year using matrices of probabilistic distributions of GB net interconnector (IC) flows, which the DDM uses to calculate GB fleet equivalent firm capacity (EFC) values for interconnection by year and scenario (see 3.3.2). Although the matrices of distributions cover a wide range of GB margin ranges, it is only the distributions for negative GB margin ranges that influence the EFC values.

In the 2022 ECR, we showed that the distribution of interconnection flows for individual countries in modelled tight hours is bimodal with interconnectors either flowing at max capacity (or near to it) or (at or close to) zero. At the GB fleet level however, for the 2022 Base Case T-4 year this effect was diluted but there was still a proportion of time where the imports were low as well as a larger proportion of time when imports were at or near to the maximum (see Figure 30 of the 2022 ECR).

In this development project, we expanded the 2022 ECR analysis of GB fleet level flow distributions in tight hours using the pan European modelling assumptions in the 2022 ECR to cover the 2022 ECR T-1 year as well as the T-4 year and the 2022 FES as well as the 2022 Base Case. We used these GB fleet distributions to update the matrices of distributions for negative GB margin ranges and tested the impact on the 2022 ECR capacity to secure modelling results used in auction target setting. We found that using the revised interconnection distributions had little or no impact on the capacity to secure or margin for 3 hours LOLE and no impact on the 2022 ECR Least Worst Regret (LWR) outcome.

On the basis of these results, even though there was no significant impact in the DDM modelling outcomes, we decided to use these updated GB interconnection distributions for the 2023 ECR because they better aligned the DDM modelling of GB interconnector flows in tight hours in the scenarios to the way that interconnected country de-rating factors are modelled.

Storage de-rating factor methodology (PTE 71)

We de-rate storage using an incremental equivalent firm capacity (EFC) methodology described in our briefing note[24]. This methodology has been in place since 2018, and in the intervening years over 1GW of storage has connected to the GB system, which combined with initiatives to provide wider access to the balancing mechanism, has made available additional operational data on storage performance. This new data has been accompanied by increasing CM contracted battery storage, with approximately 5GW of nameplate capacity secured in the T-4 auction for delivery in 2026/27. These two trends provided a significant opportunity to review the current storage de-rating methodology.

The PTE’s 2022 report recognised this via their recommendation “To consider the use of operational data for estimating battery derating factors instead of, or in combination with, the model-based EFC approach used at present”. In response to this recommendation, we have initiated a review of our storage de-rating factor methodology. This includes the overall approach taken (e.g. operational data based or model based) as well as constituent assumptions (e.g. technical availability, storage charge levels). We are currently finalising our review and are discussing our findings and recommendations with Government and the PTE. Should we agree any changes, these would be subject to industry consultation and additional consultation by Government on changes to the CM rules. We expect that, subject to these steps, we would make any resulting changes to our methodology for the 2024 ECR.

Ancillary services and the CM (PTE 68)

We account for ancillary services in our capacity to secure recommendation via the reserve and response quantities held for the loss of the largest single unit (for example, a generator or interconnector) expected in the target year for each auction. The ESO is required to plan, develop and operate the system in accordance with the security and quality of supply (SQSS) standard which includes provisions for frequency deviations after the loss of any single generating unit. Therefore we add the de-rated reserve and response values to the demand distribution in our capacity to secure calculation.

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[24] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Storage%20and%20Renewables%20De-rating%20Factors%20Briefing%20Note%202023.pdf

The PTE recommended in their 2022 report that the ESO *"..consider if the capacity of facilities providing ancillary services is being accounted for properly in the resource adequacy calculation under stress events."*

Based on this recommendation, we have aligned the services and volumes in our reserve and response for largest loss calculation with our expected procurement approaches, which have seen some significant development over the last few years with response and reserve reform initiatives[25][26]. These updates reflect our current estimate of what services we will procure to secure the largest single unit loss including:

- Reserve: short term operating reserve (STOR)
- Response: dynamic containment, dynamic moderation, dynamic regulation, static firm frequency response, mandatory frequency response, primary/secondary/high

These estimates are based on current procurement approaches; as this is a rapidly changing area, we will continue to review expected services and volumes as necessary.

Network constraints and adequacy (PTE 69)

Our capacity to secure calculation does not currently consider network constraints, for example in how these might limit the output of key generators or interconnectors during a CM stress event. The PTE have recognised this in their 2022 report, recommending that the ESO "…investigate if network infrastructure constraints present a material degradation of the achievement of the reliability standard for capacity adequacy".

We have conducted some preliminary discussions relating to this recommendation and have not seen any evidence that network constraints considerably impact adequacy at present. However, this may change in the future depending on the build out of generation, interconnection, and transmission infrastructure in GB. We will keep this under review and plan to address this recommendation in the first instance via our net zero adequacy modelling activities[27].

Interconnector modelling (PLEXOS Project)

Over the past year, the ESO has gone through a competitive tender exercise for our long-term economic modelling consultancy partner who provides both the modelling software along with data and support. This has been a joint exercise by the major internal groups: the Strategic Network Development team (responsible for publishing the Network Options Assessment), Energy Insights (responsible for publishing the Future Energy Scenarios) and the EMR Modelling team. AFRY (formally Poyry) have been our partner since 2016 when we first started using their pan-European model, BID3. The tender was won by Energy Exemplar and their model, PLEXOS, in partnership with Baringa for providing data and consulting support.

Our change management process for moving onto the PLEXOS software from BID3 has included extensive quality assurance and unit testing. These processes have given us confidence in the like-for-like nature of the two systems for modelling pan-European market dispatches, the fundamental modelling mode. This has involved checking plant dispatches, prices, interconnector flows and

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[25] https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/future-frequency-response

[26] https://www.nationalgrideso.com/industry-information/balancing-services/reserve-services/future-reserve-services

[27] See recommendation 4 on page 5 of https://www.nationalgrideso.com/document/273781/download

many other heuristics to check we have a close starting point in PLEXOS for parameter setup as BID3.

Additionally, we have been working hard to implement the modelling process that we have built within BID3 for the interconnector de-rating factors into PLEXOS and calibrating the two models. We will continue broadly with the modelling methodology used for the 2022 ECR focusing on 102 stress periods identified from 34 historic weather years, 1985 – 2018, in line with a Reliability Standard in Great Britain of 3 hours per year loss of load expectation (LOLE).

Along with the model change we have had a set of European scenarios built to work with our FES 2023 scenarios. The European dataset is made up of a forward view out to 2028 which is built from Baringa's best view of market intelligence and two divergent scenarios out to 2050 created from the scenario building tools within PLEXOS. The second set is out of scope from the ECR 2023. The market intelligence that supports Baringa's central view will influence our sensitivities to allow for a more detailed inspection of potential outturn of European generation and demand.

Finally, our historic weather data provider has also switched from AFRY to Baringa.

3.5 Modelling Enhancements since Last Report

We have further streamlined and automated the tools used to translate the data and assumptions from the FES scenarios and Base Case into the DDM, resulting in a reduction in the time taken to set up the DDM runs and a reduction in potential errors. It is necessary to carry out such process efficiency improvements each year as the complexity of the modelling and volume of data increases year on year.

We have also used an updated version of the DDM (version 6.1.91.1) that includes the new functionality to model non-delivery probabilistically and have updated the GB interconnection fleet probability distributions used in the capacity to secure modelling (see 3.4.2).

3.6 Quality Assurance

When undertaking any analysis, the ESO looks to ensure that a robust Quality Assurance (QA) process has been implemented. The ESO has previously worked closely with DESNZ' Modelling Integrity team to ensure that the QA process is closely aligned to DESNZ' in-house QA process. In addition, the PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Within ESO, the process has governance under the Director UK Electricity System Operator.

Further details of the QA checks are included in Annex A.10.

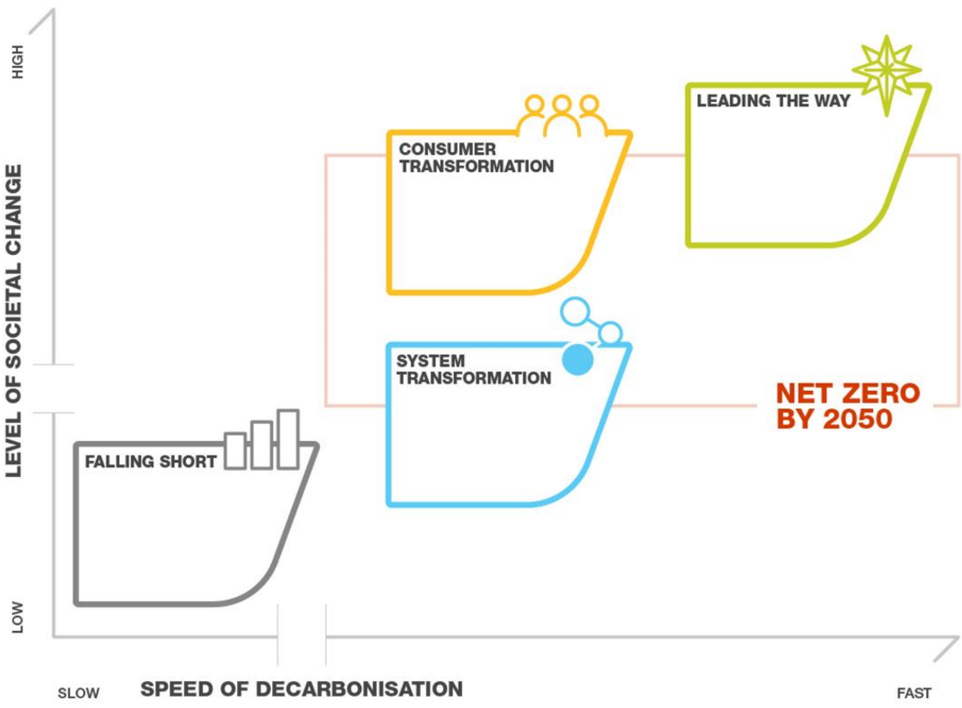
4 Scenarios & Sensitivities

4.1 Overview

The 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 the ESO's Future Energy Scenarios (FES) [28]. 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[29], Network Options Assessment[30]), operability (System Operability Framework[31]) and security of supply (ECR, Winter Outlook Report[32] and Summer Outlook Report[33]).

The FES 2023 scenario framework has been designed to explore the most fundamental drivers of uncertainty in the future energy landscape and is shown in Figure 12.

Figure 12: FES 2023 Scenario Framework



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

[29] https://www.nationalgrideso.com/research-publications/etys

[30] https://www.nationalgrideso.com/research-publications/network-options-assessment-noa

[31] https://www.nationalgrideso.com/research-publications/system-operability-framework-sof

[32] https://www.nationalgrideso.com/research-publications/winter-outlook

[33] https://www.nationalgrideso.com/research-publications/summer-outlook

For FES 2023, we are retaining the same scenarios and framework that has been used since FES 2020, as we believe they are still fit for purpose. Within our FES 2023 Call for Evidence, we asked stakeholders if they were happy for us to retain the same scenario framework for FES 2023. Overall people that responded to the Call for Evidence are happy with the framework and appreciate the consistency over the years since it enables easier year-on-year comparison. This means we have retained both the *speed of decarbonisation* axis and the *level of societal change* axis.

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. Falling Short 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 2023.

For the purposes of modelling scenarios for the Capacity Market, DESNZ’s DDM model has been used, as described in both Chapter 3 and the Annex A.6. 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 and reflect what has actually happened in the market post auctions, incorporating any potential for over-delivery rather than the theoretical recommended target capacity.

In addition to the four FES scenarios, we have used a Base Case which generally aligns with the FES ‘Five Year Forecast’ to 2027/28, against which all the sensitivities will be run. Our Base Case has a small number of significant differences to the Five Year Forecast, notably we choose to assume no new nuclear in our Base Case for 2027/28, while the Five Year Forecast assumes one new unit. The Five Year Forecast 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. The energy prices spikes seen over the past year have driven additional uncertainty in the short term. In light of this we have spent additional resource this year on our short-term forecasting over the next five years out to 2028. The additional focus on the Five Year Forecast is designed to give insight on our current trajectory and how it compares to our net zero pathways. Due to the inherent uncertainty across the market beyond 2027/28, 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 2023, the Base Case is closest to the System Transformation scenario and so we have aligned the Base Case to this scenario from 2028/29 onwards in our ECR analysis. More detail on specific drivers of change in our Five Year Forecast can be found in this year’s FES 2023 document, due to be published week commencing 10 July 2023.

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.

4.2 Scenario Descriptions

Descriptions of the four scenarios in FES can be obtained from FES 2023[34] which is expected to be published on 10 July 2023. Details of some of the key assumptions in the scenarios that are most relevant to our modelling are included in the subsequent charts in the rest of Chapter 4.

4.3 Demand Forecast

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 the 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 is assumed to participate 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 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. In our peak demand forecasts for the Base Case and FES 2023 scenarios we assume no peak demand suppression due to COVID-19 within our forecasts. Peak demands in the near term are similar to FES 2022, with some small changes impacting demand forecasts across this time horizon that are detailed below. More rapid electrification of heat and transport starts to have an impact to increase peak demands in the mid-2020s.

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

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

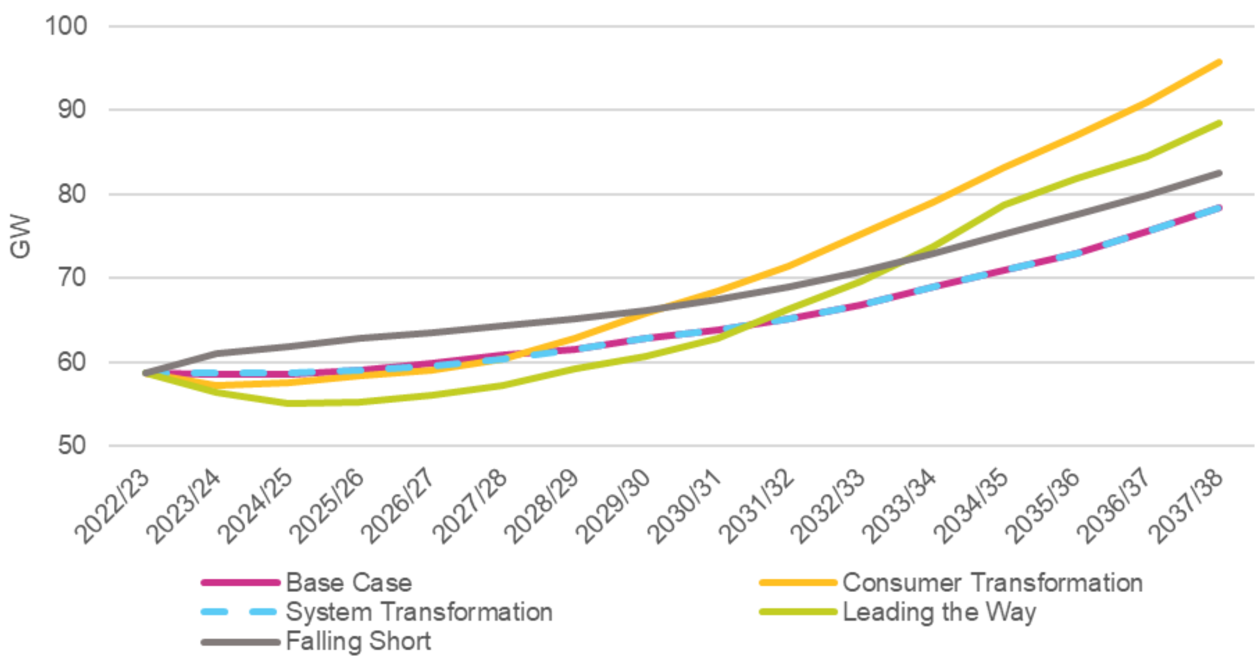
[36] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual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

Our annual demand forecasts see our Five Year Forecast electricity demands consistently lower than those in FES 2022. We have seen a 9.5 TWh drop in demand from 2021 to 2022 in response to spike in electricity prices, cost of living and economic downturn. Electricity prices expected to fall slightly over 2023, but the effects of slow or negative economic growth to continue into 2023 and 2024. Businesses who buy energy in advance are likely to continue to be affected by high energy prices into 2024, and all consumers are expected to be impacted by cost of living and reduced economic activity. Beyond 2024 we see energy demand grow as economic activity grows, with electricity demand growth driven by some new electricity demand including new homes or new electrolysis demand and some switching from gas/other fuels to electricity.

In Leading the Way, there is a smaller fall in peak demand in the near term than in FES 2022. This aligns it with the uncertainty range we have calculated around the Five Year Forecast, reflecting the additional work we have done to quantify this. We have developed uncertainty ranges around our peak demand figures from statistical analysis of historic outturn demand. Probability distributions have been developed for each sector model that informs the sub-divisions of peak demand. These are fed into a Monte Carlo model to develop sector and total demand uncertainties. This has allowed us to understand the breakdown of the contribution of each type of uncertainty to our peak demand forecasting.

Figure 13 shows the peak demands for the Base Case and the FES scenarios over the next 15 years.

Figure 13: Peak Demand - FES Scenarios and Base Case to 2037/38



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.

After the mid-2020s, 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), the speed of adoption of these and the rate at which industrial fuel switching away from fossil fuels takes place.

In the 2030s, electricity demand continues to increase. Accelerated industrial fuel switching including electrification increases electricity demand for both peak and annual demands in the industrial sector. New demand from growing sectors such as data centres increase commercial electricity demands at both annual and peak. Transport demands are affected by greater electrification of HGVs through the 2030s, particularly in Consumer Transformation and Leading the Way. Residential and commercial premises also see more rapid heat pump adoption in these scenarios increasing electricity demand. Please refer to Annex A.1 for details on the demand assumptions used in the FES scenarios.

4.4 Generation Capacity

Our generation capacity assumptions from 2022/23 to 2027/28 are based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years. There is little change in total generation capacity from FES 2022 in the early period to 2028, with the changes seen mostly driven by the most recent Capacity Market auction.

We assume that the price of the UK Emissions Trading Scheme (ETS) is 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.

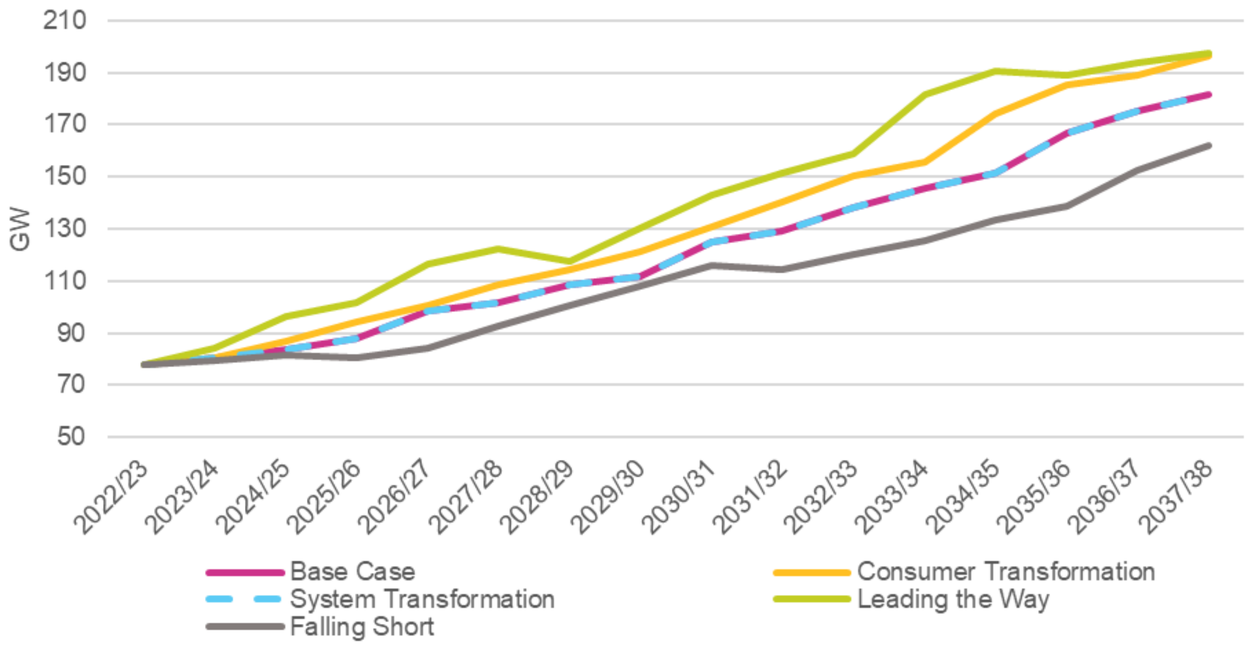
We consider the impact of the Industrial Emissions Directive (IED) on both large plant (via the EU's Large Combustion Plant Directive) and medium plant (via the Medium Combustion Plant Directive (MCPD)) and the more onerous rules applied by Department for the Environment, Food and Rural Affairs (DEFRA). For large plants, we consider the impact on a case-by-case basis as the option that each generator takes has an impact on the expected running hours and closure date. For example, those plants 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 30 September 2024[37].

Like with large plants, the emission limits for medium plant depend on numerous factors including the build date and whether the plant was awarded contracts in previous capacity auctions. We assume there will be a transition away from diesel reciprocating engines because of the emissions directive and the general market conditions.

Figure 14 shows the transmission connected generation capacity assumed over the next 15 years.

[37] https://www.gov.uk/government/publications/the-environmental-protection-england-extension-of-limited-lifetime-derogation-end-dates-direction-2022

Figure 14: FES 2023 transmission connected nameplate capacity to 2037/38



After 2027/28, each of the FES scenarios has a generation background that is based on the underlying scenario assumptions. These generation backgrounds include varying amounts of renewable / low carbon capacity, and differing volumes of Capacity Market eligible plant.

Capacity Market eligibility

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

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

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

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 0.3 to 0.6 GW over the period to 2027/28 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 assumed in each scenario will enter the Capacity Market and
- No capacity will opt-out and remain operational.

However, we recognise that with an aging fleet of power stations these assumptions are unlikely to hold true. Therefore, the recommended capacity to secure will be adjusted to account for known opted-out plants 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.

The Data Workbook (Figure 44 worksheet) 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 2023 document is published in week commencing 10 July 2023[38].

4.5 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[39].

A variety of data sources[40] 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, 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. This year we have revised the data sources used in our modelling of distribution connected solar PV generation which has had the effect of increasing our baseline installed capacity of solar PV in 2022 by 1 GW, however as discussed above this will not affect our modelling here.

Figure 15 shows nameplate capacities (excluding solar) for distributed generation out to 2037/38.

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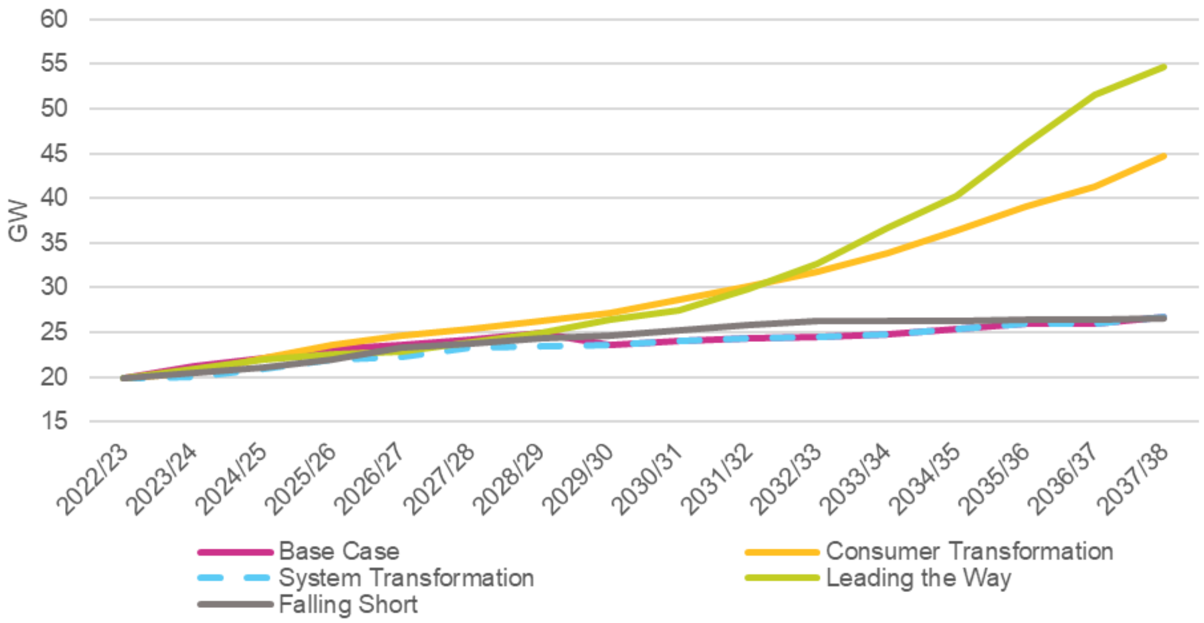
[38] The ECR 2022 modelling was carried out using the FES assumptions that were provided on 19 April 2022. Since then, some small changes have been made, particularly to assumptions in later years, which do not impact our recommendations. However, this may result in an apparent discrepancy between the FES data included in the 2022 ECR and that published in FES 2022 (available July 2022)

[39] The de-rating factor for solar is less than 6% for CM auctions

[40] For example, Renewable Energy Planning Database, CM register, DNO long term development statement and others

Figure 15: Distributed generation nameplate capacity (excluding solar) to 2037/38



4.6 Demand Side Response

Consumers have a key role to play in Great Britain's transition to Net Zero. Our scenarios with higher levels of societal change, Leading the Way (LW) and Consumer Transformation (CT), make assumptions about consumers being a driving force in reaching Net Zero, through their increasing awareness of climate change and desire to be part of the energy transition. This can include measures such as (but not limited to) using more energy efficient appliances and becoming more involved with Demand Side Response (DSR) services.

In FES, DSR has been defined as a deliberate change to an end user's natural pattern of metered electricity consumption brought about by a signal from another party. That is, demand shifting or demand reduction and not the use of generators to substitute the supply source. So, for instance, Triad avoidance is made up of both demand reduction 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.

With the launch of the Demand Flexibility Service (DFS) in November 2022, consumers have been able to engage with the energy transition in an entirely new way. This has allowed customers to receive financial incentives of at least £3/kWh to reduce their energy usage at specific times, the first time that consumers have played a direct role in balancing the electricity network.

This section considers the importance of consumer flexibility in reaching Net Zero. As we approach 2050 and greater volumes of renewable generation are connected to the grid, DSR services will become increasingly important to help balance supply and demand during peak times.

Residential, Industrial and Commercial DSR

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

Next, 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 3.1). Furthermore, in the capacity auctions, DSR competes with other types of new / existing eligible capacity to meet the capacity requirement.

We expect that for the next ten to fifteen years, in all the long-term scenarios for residential, industrial and commercial DSR, shown in Figure 16, there is a growth and development in the enabling systems, such as information communications technology, which permit DSR to evolve. There is still uncertainty around the impact of the 2019 Targeted Charging Review[41] demand for residual reforms which were implemented in April 2022 and 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 no longer reduce system charges to the extent they did previously. The commercial driver for DSR has pivoted away from system charges and moved 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).

The chart in Figure 16 shows the residential industrial and commercial DSR for the scenarios up to 2037/38. There is uncertainty in the range of projections in the next 5-6 years and we may observe more demand reduction than in the previous years because of possible participation in the DFS or another similar service. Leading the Way and Consumer Transformation present the highest consumer engagement and therefore, DSR levels. Falling Short is the scenario where we are expecting the least amount of decarbonisation, electrification and therefore flexibility. DSR levels ramp up in the years of 2024 and 2025 for this scenario since margins were deemed to be tight and therefore there was the expectation that DSR would be required to bridge the gap to meet loss of load expectation.

Moving forward over the next ten to fifteen years, there is growth in DSR across all scenarios. In Falling Short, 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 the other net zero scenarios. As demands are lower when comparing with other scenarios, there is less industrial and commercial demand, and less DSR potential. Therefore, of the net zero scenarios, System Transformation has the lowest DSR levels. In Consumer Transformation, as hydrogen is a premium fuel, industrial and commercial demand

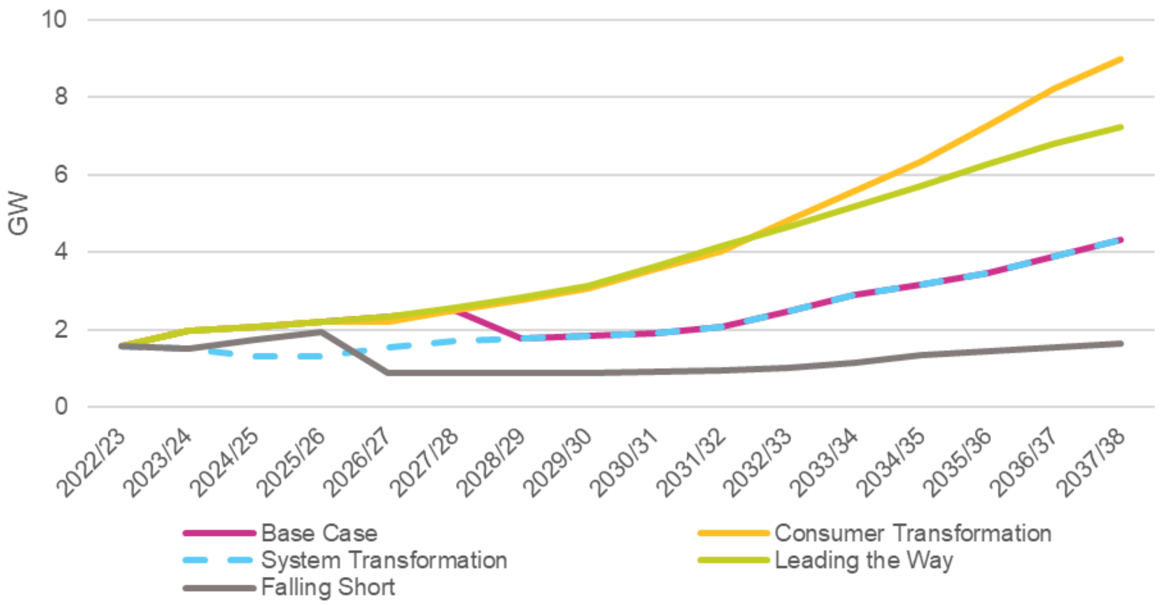
[41] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

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 FES 2023 scenarios and therefore the highest levels of DSR towards the future years. Although lower than Consumer Transformation, Leading the Way also has relatively high levels of DSR as this scenario reflects a rapid drive to as efficient and smart a system as possible.

According to stakeholder feedback and our own internal analysis, our long-term scenarios, i.e., post 2028, remain credible and have not been changed this year. Therefore, the ranges mentioned in 2023 are like those in 2022. The range of DSR by 2036/37 is 1.4GW – 6.1 GW, which is less, although overlaps the FES 2021 range of 2.1 GW – 7.5 GW by 2035/36 modelled in FES 2021. This reflects the ongoing uncertainty due to the targeted charging review and the reduction in proportion of industrial peak demand which can be shifted compared to 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.

Figure 16: Residential, Industrial and Commercial DSR to 2037/38

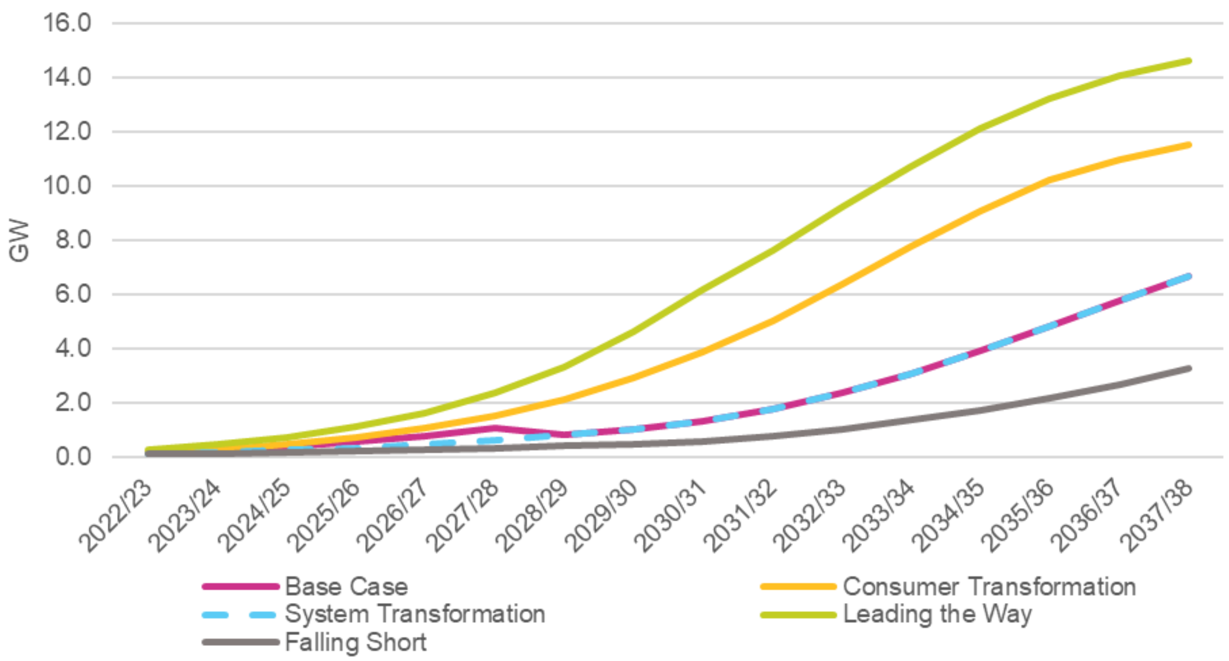


Transport DSR

Smart charging and Vehicle-to-Grid behaviour will play an important role in the future energy system and the Net Zero transition. Across all FES, cars are primarily electrified, increasing electricity demands and requiring strategies to manage how they are charged, and how system costs are distributed. However, this presents an opportunity to increase system flexibility, integrate renewables and better match supply and demand. With suitable incentives and automation, drivers will be able to reduce their transportation costs at the same time as reducing the costs of operating the energy system.

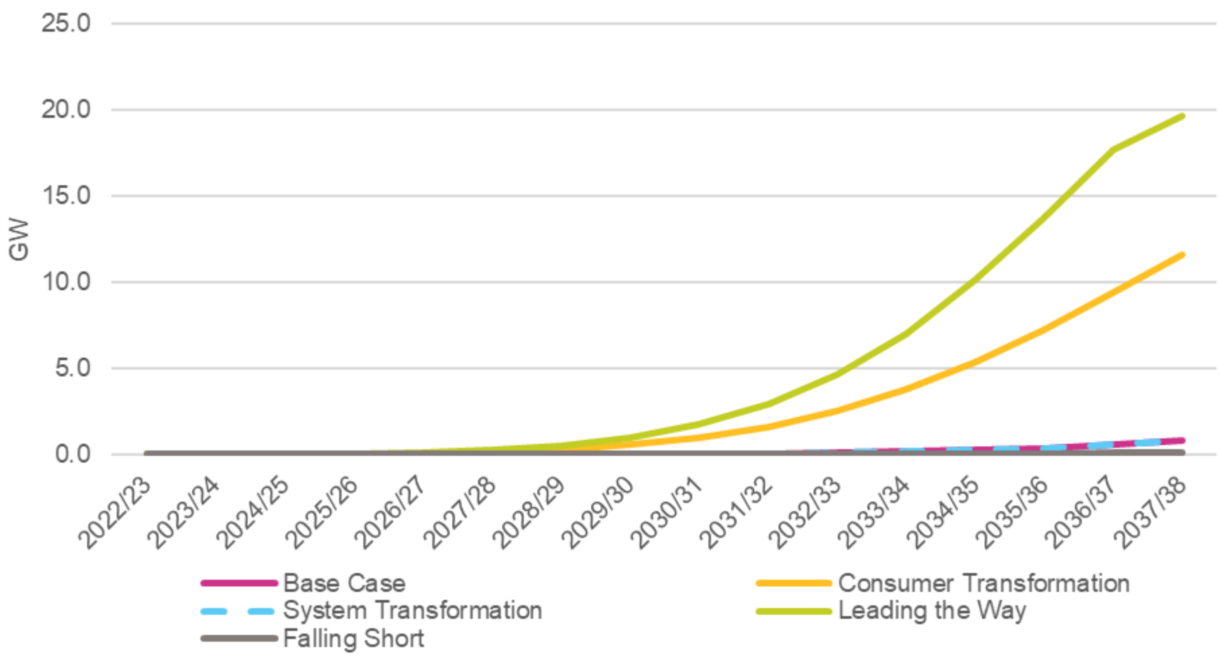
The short-term peak demand reduction for smart charging is a result of assuming both that EV uptake is an average of the other scenarios and that engagement in smart charging is an average of the other scenarios. Without baseline figures for consumer engagement in smart charging, it is difficult to conclude that the peak reduction in the short-term is likely to be closer to any one scenario. We remain positive about engagement in the near term from measures, such as mandating that home charge points be smart enabled. However, there is still a knowledge barrier to engaging, even as EV tariffs come back to market. Further clarification on how to smart charge, its benefits and how to select a tariff; at the point of sale of the vehicles, charge point or tariff could help. We would also need greater availability of data, such as how many suppliers' customers are on EVs or time-of-use tariffs, to better understand what today's engagement levels are.

Figure 17: Peak demand reduction from smart charging



Next, as V2G is still a nascent technology, there is large uncertainty in the near term as to the point at which it takes off. The scale of V2G's deployment and its consequent ability to provide flexibility to the electricity system is uncertain. We assume that prior to 2025 volumes are negligible as this is when we expect barriers to be overcome such as bi-directional CCS charging and Market wide Half Hourly Settlement. We only expect volumes in the meantime to be from small scale trials. The Near-Term View forecasts <0.2GW of available export capacity at peak in 2029. We believe this is possible due to on-going trials, but this will need to be accompanied by a reduction in the cost of bi-directional chargers and an increase in business models available to consumers.

Figure 18: Peak demand reduction from V2G



Power Responsive

Power Responsive[42] is a stakeholder-led programme, facilitated by the ESO, to increase participation in flexible technology such as DSR, small scale generation and energy storage. Power Responsive class these technologies as demand side flexibility (DSF).

The programme brings the DSF industry and energy users together to work in a co-ordinated way. A key priority is to increase 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 in balancing the system; and
- Power Responsive is overseen by a high-level steering group, composed of representatives from government, the regulator, system operators, and industry players.

4.7 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects that we aggregate to produce a total capacity of interconnection for each year. 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. In the short-term our Base Case mainly consists of projects that have started construction or have taken a final investment decision,

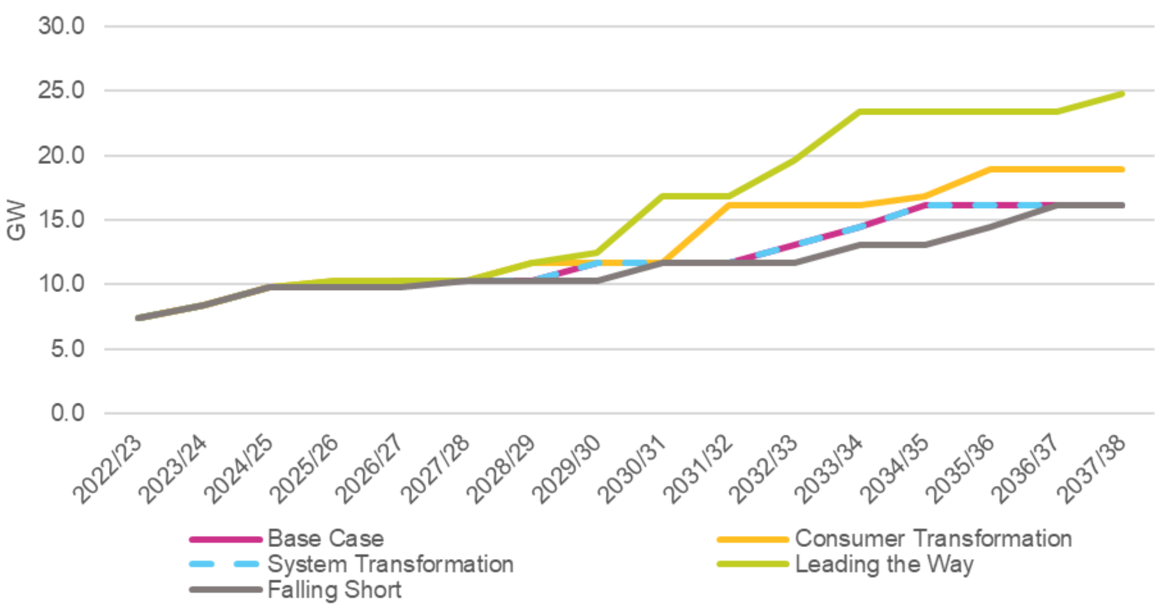
[42] https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive

as these have greater certainty around their connection dates. Beyond this there is significant uncertainty in the longer term outlook for new projects as there is a strong pipeline, but a range of barriers that can delay or obstruct development.

We identified potential projects and their expected commissioning dates to connect to GB. This information was derived from a range of sources including the 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. 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.

Figure 19 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. Moving beyond 2030 towards 2050, Leading the Way has the highest electricity interconnector capacity followed by Consumer Transformation, System Transformation and lastly Falling Short. The Base case has been aligned to System Transformation.

Figure 19: Nameplate Import Capacity Levels for Interconnection (GW)



4.8 Sensitivities

Our modelling reflects uncertainty in future electricity supply and demand through the assumptions in the FES and Base Case. This includes uncertainty in generation, storage, and interconnector capacity, as well as peak demand and DSR. In addition, the LOLE calculation for each of the scenarios and the Base Case also reflects the natural variability of demand that may occur throughout the winter, wind output, availability of generation capacity and interconnector flows.

We also model sensitivities to assess uncertainties not fully reflected in the underlying scenario / Base Case assumptions or their associated LOLE calculations. Sensitivities are only applied to the Base Case such that only one variable is changed at a time. Further details on the sensitivities, including ones that were considered but not modelled, can be found in Annex A.6.

4.8.1 Weather

This sensitivity covers the potential uncertainty due to weather that may occur in a particular winter. The LOLE calculation in our modelling uses a relatively short weather history of 16 years. This means that we cannot be confident that this set will be statistically 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.

The cold winter sensitivity is based on assessing the impact if the weather we experienced in winter 2010/11 were to happen again. Specifically, we use the demand and wind from winter 2010/11 only in the LOLE calculation instead of the full 16-year history that we use in the Base Case. The warm winter sensitivity is based on assessing the impact if the weather we experienced in winter 2006/07 were to happen again. Specifically, we use the demand and wind from winter 2006/07 only in the LOLE calculation instead of the full 16-year history that we use in the Base Case. 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 16-year history. These winters do not represent best or worst-case scenarios as our relatively short history will not cover all potential weather scenarios.

4.8.2 High / Low Plant Availabilities

This sensitivity covers the potential uncertainty in the availability of conventional generation capacity. Conventional plant availabilities are based on the mean availability of the fleet during the winter peak period over the last seven years. As an average over a relatively small sample of seven data points, there is a statistical uncertainty in the mean value. This also means that there is a statistical uncertainty in the distribution of conventional generation used in the LOLE calculation. This sensitivity is therefore justified as the mean values may not fully reflect the statistical uncertainty of what may occur in future years.

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 T-1 auction for delivery in 2024/25. There is no material impact on the analysis for the T-4 auction for delivery in 2027/28 as the majority of capacity for that delivery year has yet to be secured.

Table 3 shows the availability assumptions used in this sensitivity. The low availability sensitivity assumes the availability of CCGT / CHPs and nuclear are one standard deviation below their mean values. The high availability sensitivity assumes the availability of CCGT / CHPs is one standard deviation above its mean value. We no longer apply the high availability sensitivity to nuclear as the availability of the fleet has not reached such levels in the last five winters. 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. We believe it is more appropriate to consider the uncertainty around interconnectors in the over- and non-delivery sensitivities.

Table 3: Assumptions for the low and high availability sensitivities

Technology	Low availability	High availability	Base Case

CCGT	90%	93%	92%
Nuclear	73%	N/A	78%

4.8.3 Low / High Demand

This sensitivity covers the potential uncertainty in forecasting the Base Case peak demand. The LOLE calculation reflects the natural variability of demand through a distribution. This distribution is based on historical half-hourly demand values from our 16-year history, which is scaled by the ratio of future peak demand to historical peak demand. The uncertainty in the future peak demand forecast leads to a statistical uncertainty in the demand distribution used in the LOLE calculation.

We completed a development project this year to understand sector model (e.g. heat, transport) uncertainties in our demand forecast (see section 3.4.2), and have combined these with the metered demand and losses uncertainties modelled last year in a Monte Carlo model. We use the 10% and 90% percentile values from this model to define the low and high demand sensitivities, which are set out in Table 4. Note that these sensitivities only apply in the years up to and including 2027/28.

Table 4: Peak demand assumptions for low and high demand sensitivities

Delivery year	Sensitivity		Base Case (GW)
	Low demand (GW)	**High demand (GW)**	
2024/25	57.2	61.0	58.5
2027/28	60.1	64.2	60.9

4.8.4 Non-delivery

This year we updated our approach to model future unknown non-delivery (providers that are unable to deliver in line with their Capacity Market agreements for the entire winter peak period, that isn't known to us at the time of the modelling). We implemented a 6% average non-delivery probability to CM-eligible capacity (except wind and interconnection) in all DDM runs (see Section 3.4.2), except for the Falling Short scenario where we have used 5% (T-4) and 5.5% (T-1).

We have continued to model non-delivery sensitivities (with 0.4 GW increments) away from the Base Case in the 2023 ECR, but only to provide granularity in the Least Worst Regret (LWR) calculation so it can select a value at or near the optimum. These can now be thought of as 0.4GW intervals of capacity procurement that define the regret costs of the other scenarios and sensitivities. For our capacity to secure analysis we have only included non-delivery sensitivities that fall within the range of other scenarios and sensitivities modelled (e.g. see Figure 2 and Table 18) as the higher non-delivery sensitivities are not required.

However, for comparison with the methodology used in previous ECRs only (and not for our capacity to secure recommendation), we have modelled these non-delivery sensitivities in steps of 0.4 GW up to 4.0 GW non-delivery for the T-1 auction and up to 4.4 GW for the T-4 auction. In accordance with the approach in the 2022 ECR, the maximum level was informed by considering different types of non-delivery, summing them, and allowing for potential market response.

Table 5 shows our assumptions that have informed the maximum non-delivery. Further detail on these assumptions is provided in Annex A.6.1.

Table 5: Maximum non-delivery assumptions

Category	T-1 (GW)	T-4 (GW)
Large thermal	3.0	3.9
Nuclear	1.8	0.0
Small thermal and storage	0.7	1.8
Unproven DSR	0.3	0.3
Interconnectors	3.0	3.3
Sum of non-delivery	**8.8**	**9.3**
Potential market response	-1.7	-2.1
Total	**7.1**	**7.2**
Base Case Adjustment (minus average non-delivery of ~3.0GW)	**4.0 (rounded to nearest 0.4)**	**4.4 (rounded to nearest 0.4)**

As described in Section 3.4.2, we updated our estimates of historical non-delivery in the CM over the winter peak period (December to February, when demand is at its highest) as part of development project PTE60 Phase 2. This was carried out using data from CM registers, REMIT outage information and other sources in January 2023. It considered different types of winter non-delivery and when it became apparent to us, such that we could reflect it in our ECR recommendations or in the final T-1 auction target (determined following the demand curve adjustment after prequalification and after which no further action can be taken). The timing of when non-delivery becomes apparent is uncertain as it depends on factors such as when terminations take place, when CM registers are updated, winter outages are known, and when assumptions on the ECR Base Case are finalised which means that data on when the non-delivery became apparent may be less accurate than the total non-delivery figure.

Table 6 shows the estimated de-rated non-delivery total by delivery year and includes:

- Capacity Market Units (CMUs) with terminated CM agreements covering the year
- CMUs with non-terminated multi-year CM agreements that were subsequently reduced to 1 year (resulting in non-delivery for years after the initial year)
- New CMUs with non-terminated CM agreements that had not met their minimum completion requirement by the winter of the delivery year
- Unproven DSR CMUs with non-terminated CM agreements that had not completed metering assessments by the winter of delivery year
- CMUs with non-terminated CM agreements with outages over whole winter of the delivery year that had not secondary traded their obligations by the start of winter
- for 2022/23: winter outages over the whole winter that were known in January 2023

The 6% non-delivery percentage was chosen as this gave a modelled non-delivery of around or just over 3 GW, similar to the average non-delivery observed in the most recent 5 delivery years that occurred after the final T-1 target had been set following prequalification (see Table 6).

Table 6: Estimated total historic winter non-delivery for recent years (from project PTE60 Phase 2)

Delivery Year*	Total since agreements were awarded (GW)	Total Post T-4 ECR Recommendation (GW)	Total Post T-1 ECR Recommendation (GW)	Total Post T-1 Auction Target (GW)
2018/19	5.4	1.8	3.7	3.7
2019/20	6	6	1.1	1.1
2020/21	11.4	8.4	6.6	6.6
2021/22	9.1	7.4	7.3	1.5^
2022/23	8.4	6.6	4.2	2.8¬
Average-5yrs	**8.1**	**6**	**4.6**	**3.1**

* Delivery year 2017/18 did not have a T-4 auction. It only had a T-1 auction (known as the Early Auction). As this was not a typical delivery year and was comprised of existing capacity with one year agreements, we have excluded 2017/18 from the table. The 5 year average shown represents non-delivery observed in more typical delivery years (which include some new capacity with multi-year agreements).

^ The demand curve adjustment after prequalification that informed the target for the 2021/22 T-1 auction accounted for around 5.8 GW of non-delivery after the ECR T-1 recommendation that was either known by then or was considered to be at significant risk of occurring
¬ The ECR / demand curve adjustment after prequalification that informed the target for the 2022/23 T-1 auction accounted for around 1.4 GW of future non-delivery that was either known by then or was considered to be at significant risk of occurring

As reported in the 2021 Electricity Capacity Report, we carried out a development project to estimate the potential CM-eligible capacity that remained operational in each winter from 2017/18 to 2020/21 without a CM agreement (referred to as over-delivery) to address recommendation 54 from the PTE in their 2020 report. We found that the level of over-delivery that we could be certain of declined over this four year period to a very small amount (~0.4 GW) due to the closure of surplus capacity (e.g. coal units) without agreements. Over the same time period non-delivery increased reaching a high level in 2020/21. High levels of non-delivery have also been observed since 2020/21. The reduction in over-delivery combined with high levels of non-delivery means that we can no longer rely on over-delivery to maintain adequate winter margins: we need to ensure that we account for the risk of non-delivery in our target capacity recommendations

4.8.5 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 have already assumed in the Base Case.

While we currently model non-delivery and over-delivery sensitivities separately (due to different drivers), they can in essence, be considered as a continuum of net delivery. On this basis, we think it is appropriate to model them consistently with different types of over / non-delivery and associated market response. We have modelled up to 3.6 GW over-delivery in steps of 0.4 GW for the T-1 auction and up to 4.4 GW over-delivery in steps of 0.4 GW for the T-1 auction and up to 4.4 GW over-delivery in steps of 0.4 GW for the T-4 auction. Note that the Base Case for the T-1 auction already includes 0.4GW of over-delivery (see Section 2.5.2 of the 2022 ECR for details) and the over-delivery sensitivities are applied on top of this. Table 7 shows our assumptions that have informed the maximum over-delivery. Further details on these assumptions are provided in Annex A.6.1.

Table 7: Maximum over-delivery assumptions

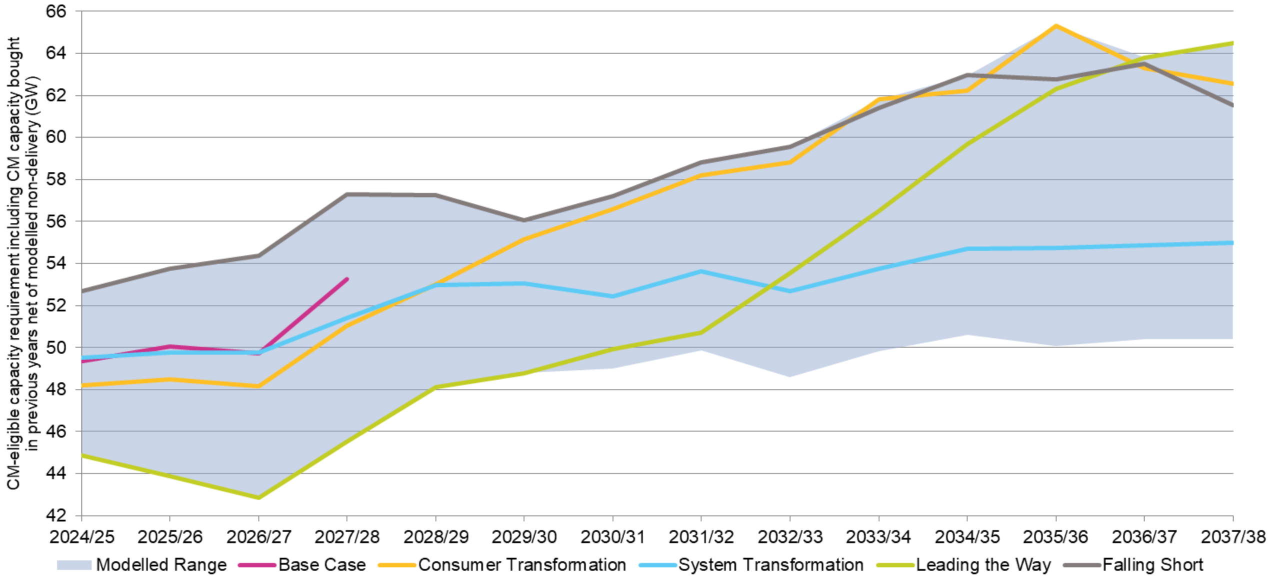
Category	T-1 (GW)	T-4 (GW)
Large thermal	1.0	1.0
Nuclear	0.0	0.0
Small embedded	1.5	1.5
Unproven DSR	0.3	0.3
Interconnectors	2.0	3.1
Sum of non-delivery	4.8	5.9
Potential market response	-1.3	-1.4
Total	**3.6** (rounded to nearest 0.4)	**4.4** (rounded to nearest 0.4)

4.9 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 (2024/25 and 2027/28). It focuses on the total requirement for CM-eligible capacity and does not split each year's requirement into capacity secured in earlier years through T-1 and T-4 auctions. The requirement in 2024/25, 2025/26 and 2026/27 was derived from the 2024/25 model runs (see Chapter 6) and the capacity requirement from 2027/28 to 2037/38 from the model runs for 2027/28 (see Chapter 7). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 20 shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years (note the shaded area corresponds to the modelled range including all scenarios and sensitivities) and net of modelled non-delivery. A table showing the data behind this chart can be found in the ECR Data Workbook.

Figure 20: 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 warm winter sensitivity 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 the chart above, the Consumer Transformation, Falling Short and Leading the Way scenarios show an increased requirement in general over most of 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. 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. In the final few years of the period, the requirement falls in some scenarios as more low carbon capacity becomes operational that is assumed to be outside of the CM.

There could be a potential risk of underutilised assets receiving support in future e.g. if new capacity is built for one year (when it is needed) that is not required in future years after that. However, in the case of coal power stations, the Government's policy is to close all unabated units by October 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. In addition, the Government has committed to a net zero power system by 2035 which is likely to result in the closure of unabated fossil fuel capacity. These closures of existing capacity will ensure that any new capacity built in the early years of the Capacity Market will still be required in later years.

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 7 of the final results report for the 2026/27 T-4 auction for delivery in 2026/27[43]. Note that the values in the 2026/27 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 T-4 auction for delivery in 2020/21 onwards. The ECR Data Workbook (DW1 worksheet) contains a summary of total capacity secured in each auction to date.

The above chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2024/25. For 2023/24, 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 2023/24 Winter Outlook Report[44] will include a view of electricity security of supply for the coming winter.

[43] See page 7 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2026-27%20Final%20Auction%20Results%20Report%20v1.0.pdf

[44] https://www.nationalgrideso.com/research-publications/winter-outlook

5 De-rating Factors for CM Auctions

5.1 De-rating Factors for Conventional Plants, Storage and Renewables

Figure 21-25 show the de-rating factors for conventional plants (and DSR), storage, and renewables. The de-rating factors cover both T-1 auction for delivery in 2024/25 and T-4 auction for delivery in 2027/28. De-rating factors from the previous year's ECR are also shown in the Figures 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.5.4.

DSR de-rating factors are calculated using the mean committed STOR availability of Non-BM STOR providers over the last three winters during high demand periods[45]. The DSR de-rating factor has increased since the 2022 ECR largely due to STOR moving from seasonal fixed contract procurement to a day-ahead auction, which has increased committed STOR availability.

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[46]. Annex A.7 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 much higher level of duration-limited storage capacity in the 2023 ECR Base Case than in the 2022 ECR Base Case (see Annex A.7 for more details). As a result of this increased capacity, the duration threshold corresponding to 95% of stress events has increased from 6 hours to 8 hours in the T-1 year, which combined with lower incremental Equivalent Firm Capacity (EFCs) also due to the increased duration-limited capacity, has resulted in larger year-on-year changes than previously in the de-rating factors .

Renewable de-rating factors are based on the methodology[47] that was consulted with the industry in February 2019. The values for wind in the 2023 ECR are similar to those in the 2022 ECR while those for solar have increased as the increased short-duration storage capacity shifts the distribution of stress events towards longer events that start earlier in the day (when there is some solar output). Further explanation of historical trends and our de-rating methodology for storage and renewables can be found in our briefing note[48].

[45] 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

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

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

[48] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Storage%20and%20Renewables%20De-rating%20Factors%20Briefing%20Note%202023.pdf

Figure 21: De-rating factors for conventional plants and DSR - detailed[49]

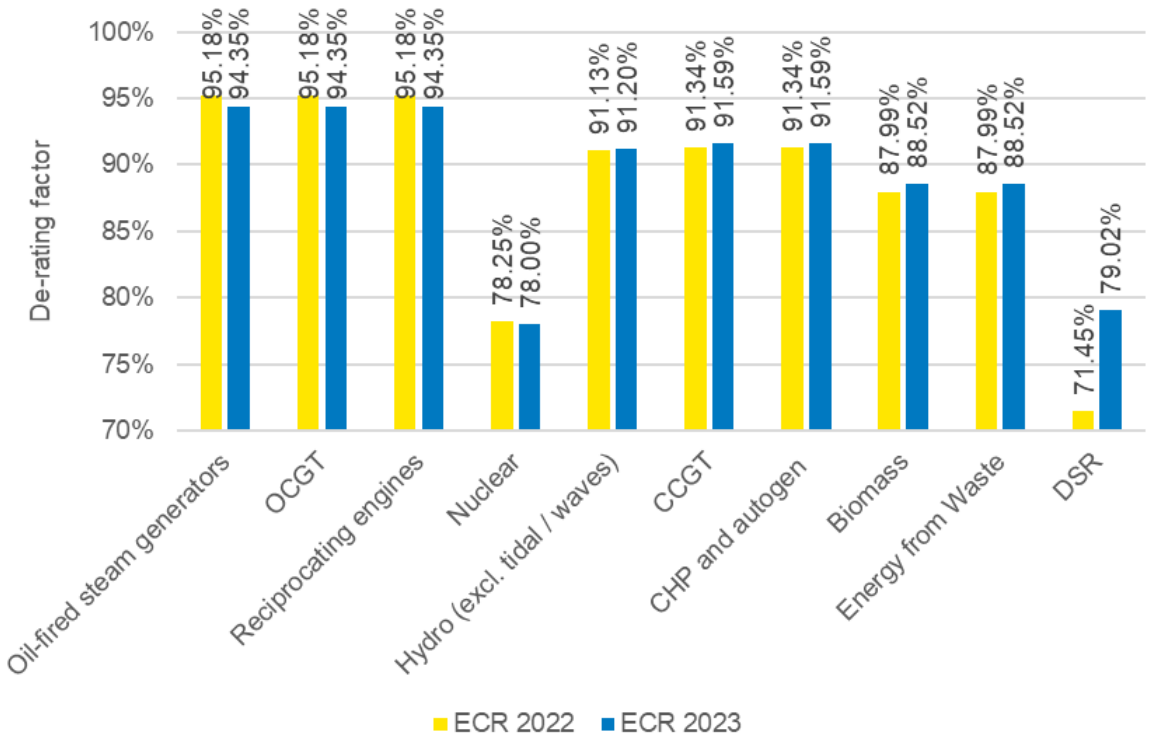
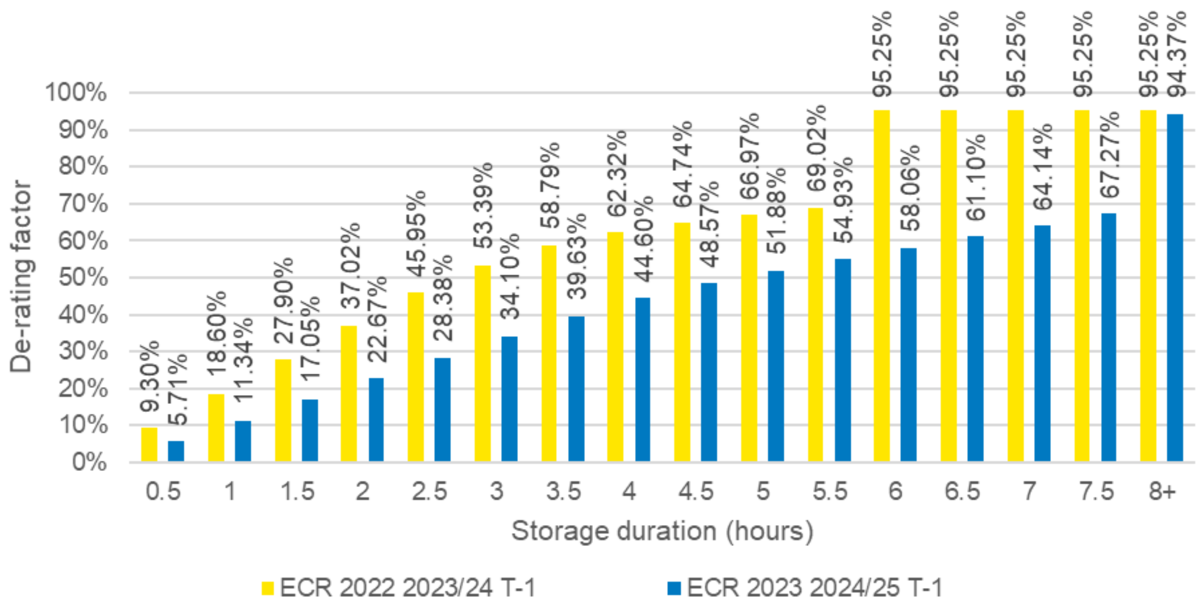


Figure 22: De-rating factors for duration limited storage T-1 comparison



[49] De-rating factors apply to both the T-1 auction for delivery in 2024/25 and T-4 auction for delivery in 2027/28.

Figure 23: De-rating factors for duration limited storage T-4 comparison

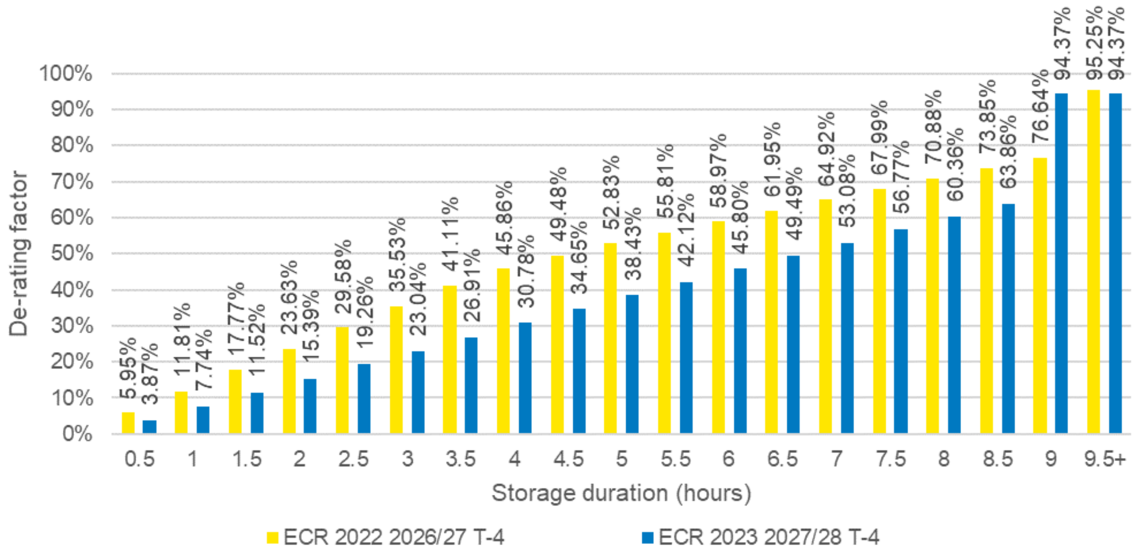


Figure 24: De-rating factors for renewables T-1 comparison

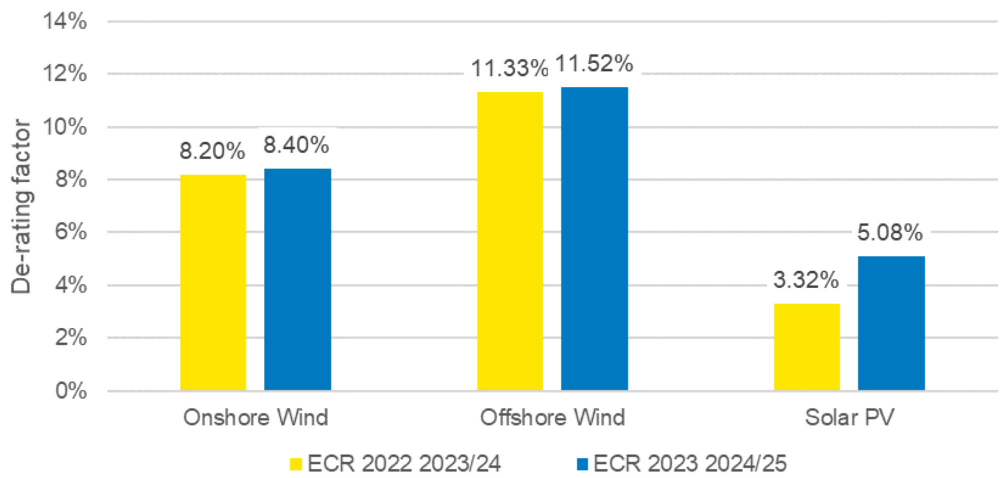
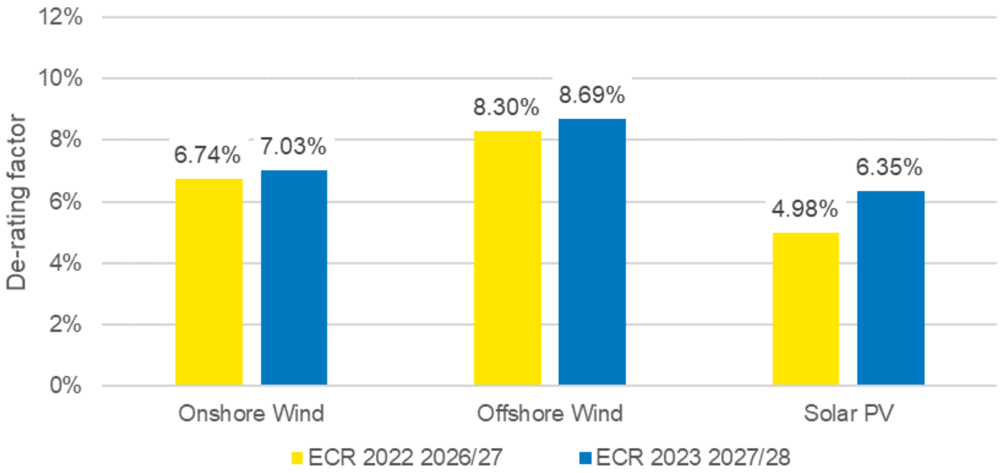


Figure 25: De-rating factors for renewables T-4 comparison



5.2 Interconnectors

Interconnectors are eligible to participate in both the T-1 for delivery in 2024/25 and T-4 auction for delivery in 2027/28 except where they already have been awarded a Capacity Market agreement. All interconnectors that are expected to be operational for the start of the 2024/25 delivery year were already awarded contracts in the T-4 auction for delivery in 2024/25. Therefore, we have not provided modelling results for the 2024/25 T-1 interconnector de-rating factor ranges in this report.

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 the ESO, in agreement with DESNZ, Ofgem and the PTE, has considered in determining an appropriate de-rating factor range for each country so that 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 DESNZ.

Further details on our interconnector modelling assumptions are included in Annex A.11.

5.2.1 Methodology

The modelling methodology in this year's ECR is broadly similar to the approach we have taken over the last three years and was set out in the briefing note published in April 2023[50]. However, we have procured a new pan-European model for completing this analysis having partnered with Energy Exemplar and Baringa after a competitive tender exercise. We now use Energy Exemplar's PLEXOS model. This means that:

- We assume that interconnectors will be participating directly in the next round of CM auctions.

[50]https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Modelling%20de-rating%20factors%20for%20interconnected%20countries%20in%20the%202023%20ECR%20v1.0.pdf

- We use our pan-European market model PLEXOS developed by Energy Exemplar[51] using core functionality of the model.
- The current modelling includes all neighbouring markets that are forecast to be connected to GB and at least every market connected to those neighbouring markets. A full list of modelled markets can be found in Annex A.11.2.
- We 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[52] (i.e. we still have unserved energy after considering imports).
- GB demand is then scaled up significantly to ensure that there is load loss in all simulated time periods. The 102 time periods with the most load loss undergo detailed modelling in PLEXOS. This is an average of 3 hours LOLE across 34 historic weather years.
- We use stochastic modelling of generator outages in Europe and sensitivity analysis to assess the potential impact of supply and demand uncertainty in Europe.
- 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.
- We assume that resources within the EU's internal energy market are prioritised to meet all possible demand in the internal energy market before demand in GB.
- 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

We have continued to make changes each year to our interconnector modelling to improve the quality and robustness of our de-rating factor ranges. This year we are using Energy Exemplar's PLEXOS model for the first time. We have taken extensive steps to ensure we can replicate our modelling approach in the 2023 ECR with that used in previous years.

For each of these scenarios and sensitivities, we simulate up to 200 different plant outage patterns to reflect the stochastic nature of these outages. We can calculate a de-rating factor for each interconnector across each sensitivity from these periods of interest as an average for all outage patterns and stress periods. For markets, such as France, which host multiple connections to Great Britain, results for each interconnector are capacity weighted and averaged to provide a derating factor per interconnected country.

However, we should recognise that taking a simple mean average, will not tell the whole story and may not reflect the underlying distribution. In other words, we don't have the full picture relating to the variability and potential risk of what interconnectors may flow during a stress event. For example, in an extreme case, a de-rating factor of 50% for a particular scenario or sensitivity, may arise from interconnectors importing at maximum for half the periods and importing zero for the remaining half. While this gives an average de-rating factor of 50%, the risk profile for consumers

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[51] https://www.energyexemplar.com/plexos

[52] See 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

would be different to a situation in which the interconnector flows during these periods were normally distributed around an average of 50%. The underlying stochastic data is available directly from PLEXOS which allows us to investigate these details more closely. This allows us to continue to build on the work we set out in last year's ECR.

We have prioritised the Base Case from the FES with sensitivities changing the supply and demand balance in Europe, rather than Britain. The other scenarios in FES have been simulated to demonstrate the range within the European Central Case.

Data sources

In the 2022 ECR, our assumptions for Europe were based on a data set that we procured from AFRY. Since last year, we have undergone a competitive tender for our pan-European modelling partners. Baringa, as one of Energy Exemplar's trusted partners, were contracted through this tender process to provide our European scenarios. These consist of a central best view, based on market intelligence, in the short-term blended with two scenarios out to 2050, for use with our Future Energy Scenarios (FES) built using economic and political levers within PLEXOS. In this analysis we have used the single central case built purely on market intelligence. We consider this to be more appropriate for our interconnector modelling, as the two European scenarios may also include new-build plant that is not yet committed and wouldn't be prudent to assume can be relied upon for GB security of supply through interconnector flows.

1. Our European scenario is consistent with the latest European policy on net zero.
2. We have a short-term central view used in ECR 2023 which is complemented by two long-term scenarios out to 2050 which are not used within this analysis.
3. We intend to publish capacity by technology and demand for European countries. These will be published as part of the ECR data workbook[3]. GB scenario assumptions will be published in the FES data workbook[17] on 10th July 2023.

Our historic weather data is now also provided by Baringa. We have modelled 34 weather years covering 1985-2018.

5.2.2 European Sensitivities

We use sensitivities to assess the potential uncertainty of supply and demand in Europe beyond the assumptions in the scenarios. Our modelling approach means that we have completed around 60,000 simulations[53] each covering 34 years' historical weather for the T-4 auction for delivery in 2027/28.

Table 8 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 8: European Scenario Sensitivities (see main text for detail)

Sensitivity Name	Description	Justification
Central Case	The European reference scenario	

[53] We have 5 scenarios in FES (Base Case + 4 scenarios) each simulated with 61 sensitivities and 200 outages cases, giving a total of 61,000. 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.

Sensitivity Name	Description	Justification
Ireland Thermal	Scaling thermal plant capacity in Ireland from 100% to 50% in 10% steps.	In their most recent All-Island Generation Capacity Statement the Irish system operators described it as "a challenging outlook for Ireland with capacity deficits identified during the 10 years to 2031[54]. This sensitivity covers uncertainty in available thermal capacity in Ireland. .
France Nuclear	Reducing nuclear plant installed capacity in France from 0GW to -20GW in 2GW steps. Accounting for the availability profile used to model maintenance outages (see the French Nuclear section in main text for details). This amounts to approximately 40GW of outage (23GW of availability) in the most extreme scenario modelled.	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. This sensitivity considers uncertainty in available French nuclear capacity beyond what is already assumed in our reference scenario.
European Gas	Scaling gas generating capacity (including OCGT, CCGT both conventional and CHP) from 100% to 75% in 5% steps.	This sensitivity considers uncertainty in available gas generating capacity in Europe. Russia's illegal invasion of Ukraine continues to impact global energy markets, including sources of gas supply for Europe. There is also uncertainty in the economic viability of large-scale thermal generation, indicated by the results of ENTSO-E's European Resource Adequacy Assessment[55] and further uncertainty due to the need to decarbonise European power systems
Belgian Nuclear	Scaling Belgian Nuclear Capacity from 100 to 0% in steps of 50%. Approximately equivalent to taking one or both of the Doel 4 and Tihange 3 Nuclear reactors out for service.	Belgium has recently extended the life of two nuclear stations beyond 2025. There is currently upcoming maintenance planned for Belgium's two nuclear reactors in 2025/26 While these reactors are expected to be available in 2027/28, this sensitivity covers uncertainty in their availability for that year too.
European Renewables Upside	An increase compared to European Central Case in expected renewable infrastructure build out to the following levels • Solar 114% • Onshore Wind 111% • Offshore Wind 119%	There is strong support from governments for the build out of renewable energy. This sensitivity covers the uncertainty that renewables are deployed at a faster rate than assumed in our European scenario.
European Renewables Downside	A reduction compared to European Central Case in expected renewable infrastructure build out to the following levels • Solar: 77% • Onshore Wind 86% • Offshore Wind 79%	Weaker global economies may impact ambitious government targets on renewable energy This sensitivity covers the uncertainty that renewables are deployed at a slower rate than in our European scenario.

[54] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid_SONI_Ireland_Capacity_Outlook_2022-2031.pdf

[55] https://www.entsoe.eu/outlooks/eraa/2022/

Sensitivity Name	Description	Justification
Netherlands, Belgium, Poland Gas	Reduction in gas-fired generation to 6.5GW in steps of 0.5GW to the following maximum levels in each of the markets • Netherlands 2.5GW • Belgium 2.5GW • Poland 1.5GW	There are uncertainties around both commissioning and decommissioning timescales of gas plant in Netherlands[56], Belgium[57] and Poland[58] that are assumed to be available in our European scenario. This sensitivity covers the uncertainty that they are unavailable.
Germany Coal Downside	Reduction in German Hard Coal generation by 1 to 5GW in steps of 1GW.	Germany needs to phase out coal to meet its decarbonisation targets. This sensitivity covers uncertainty on coal phase-out.
Germany Coal Upside	Increase in German Hard Coal and Lignite generation by 1 to 8GW in steps of 1GW.	Russia's illegal invasion of Ukraine continues to impact global energy markets. This has left to some Governments taking measures to build greater resilience in the short-term for security of supply. This sensitivity covers the uncertainty of delaying phase out of German coal and lignite.
Norway Exports	Reduced availability of Norwegian electricity exports	The Norwegian government are formalising a reporting system, introduced in Summer 2022, requiring hydropower producers to report and forecast reservoir levels to ensure that price dynamics fully capture potential risks to security of supply. This sensitivity considers the uncertainty of these resources being available leading to lower exports from Norway, which would lead to lower imports available for GB.
Celtic Link	Removal of all 700MW of interconnection provided by Celtic Link between Ireland and France.	Celtic Link is due to begin operations in 2025/26. This sensitivity covers the uncertainty that it is unavailable in 2027/28.
Ireland Thermal + Celtic Link	A combination of the Irish thermal + Celtic Link sensitivities	This combines the uncertainties associated with the adequacy outlook for Ireland and the availability of the Celtic interconnector.

Our interconnector analysis requires us to provide a range for each interconnected country. The upper end of the range is generally set by the European RES Upside. In general, the lower end of the range has typically been set by one of: French nuclear sensitivity, European gas sensitivity, Irish thermal + Celtic link availability, and availability of Norwegian hydro resources reducing exports from Norway.

Each sensitivity in Table 8 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.

Ireland Thermal

The most recent All-Island Generation Capacity Statement[59] described a "challenging outlook for Ireland with capacity deficits identified during the 10 years to 2031". Generator availability,

[56] https://open.overheid.nl/documenten/ronl-8f5930f0daa6a24784f0624178b46084a61b0330/pdf

[57] https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2022/20221028_adequacy-and-flexibility-study-2024-2034-assumptions-and-methodology-main-doc.pdf

[58] https://www.pse.pl/documents/20182/98611984/Wyniki+aukcji+g%C5%82%C3%B3wnej+na+rok+dostaw+2027

[59] https://www.soni.ltd.uk/media/documents/EirGrid_SONI_2022_Generation_Capacity_Statement_2022-2031.pdf

withdrawal of previously awarded capacity, run hour restrictions and increasing levels of demand have all been highlighted. In the FES scenarios for the T-4 auction year, Ireland is predicted to benefit from increased interconnector capacity via Greenlink and the Celtic interconnector. Even with this extra capacity the Irish operators are still expecting a deficit of between 700 and 1600 MW in T-4.[60]

For the Ireland thermal sensitivity, we reduce thermal plant capacity from 100% to 50% in steps of 10%. In previous years we have set our derating factor prediction to the scaling level that brings the market closest to 8 hours LOLE, in line with the security standard of the Republic of Ireland. To approximate this, thermal capacity in Ireland is scaled to the same absolute level as was the case for the T-4 auction in ECR 2022. Installed thermal capacity is reduced from 8850 MW to 4750 MW or approximately 50%.

France Nuclear

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 (or more) 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)[61]. More recently there have been ongoing issues related to stress corrosion first discovered in Oct 2021[62] in Civaux 1. Similar defects have subsequently been found at many other sites leading to shutdowns, inspections and unscheduled maintenance that have continued through 2022 and 2023[63].

There has been a declining trend in French nuclear generation over the past several years[64]. The impact of Covid-19 on maintenance schedules, the closure of Fessenheim and planned ten-year inspections have played a significant role.

The observed availability of the nuclear fleet in 2022 has been utilised in the modelling work to simulate realistic maintenance and outage profiles. This means that even in the reference case there are on average approximately 20GW of unavailable nuclear capacity during the winter months. At the start of winter 2022/23, available French nuclear generation was even lower than this and so this sensitivity is based on an additional 10 GW of capacity being unavailable, representing a total unavailability of approximately 30 GW of the fleet.

European Gas

The global gas market continues to recover from the impacts of Covid and Russia's illegal invasion of Ukraine. Prior to Russia's invasion of Ukraine approximately 40% of European gas came from Russia. Since then, Russian gas imports have been steadily replaced by other sources, with a heavy dependence on liquified natural gas from the United States. Further steps to protect supply have been taken by member states including steps to ensure that storage facilities are filled ahead of the winter season. The availability of gas supply could impact the availability of gas-fired

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[60] All-Island Generation Capacity Statement 2022-2031, Figure 4.1 October 2022

[61] 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.

[62] https://www.french-nuclear-safety.fr/asn-informs/news-releases/stress-corrosion-phenomenon-detected-on-reactors

[63] https://www.edf.fr/sites/groupe/files/2023-03/EDF%20Stress%20Corrosion_SSE_030622.pdf

[64] Raw data available from Rte: https://www.rte-france.com/en/eco2mix/download-indicators

generation. In addition, ENTSO-E's European Resource Adequacy Assessment indicated uncertainty in the economic viability of large thermal power generation, and there is further uncertainty due to the need to phase out thermal generation to decarbonise the European power systems. We have modelled an 18% reduction in peak gas-fired generation across the whole of Europe to consider these uncertainties.

Belgium Nuclear

Belgium delayed a planned nuclear plant phase out in 2022 keeping two of seven reactors open to 2035. Doel 4 and Tihange 3 are expected to be unavailable over winter 2025/26[65]. This sensitivity considers the uncertainty that they are also unavailable for 2027/28, corresponding to a capacity reduction of approximately 2GW.

[65] https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2022/20221028_adequacy-and-flexibility-study-2024-2034-assumptions-and-methodology-main-doc.pdf

European Renewables Upside

There is strong support from European governments for the build out of renewable energy[66]. Auction volumes and subsidies are increasing due to Russia's illegal invasion of Ukraine and net zero targets[67] [68]. Derating factors set by this sensitivity are based on a 14% uplift in solar and an 11% and 19% buildout in onshore and offshore wind respectively against the European baseline.

European Renewables Downside

Though governments have put higher targets on renewable infrastructure buildout in response to Russia's illegal invasion of Ukraine and Net Zero targets, a weaker global economy has led to increases in costs, labour shortages and supply chain issues[69] [70] [71] [72]. Derating factors set by this sensitivity are based on a 23% reduction in predicted solar and a 14% and 21% reduction in predicted onshore and offshore wind buildout respectively against the European baseline.

Netherlands, Belgium, Poland Gas

There are uncertainties surrounding gas commissioning and decommissioning timescales in Netherlands, Belgium and Poland for plant assumed in our European scenario. In the Netherlands there are 2.5 GW of decentralised gas CHP plant potentially to be decommissioned in this decade due to heating decarbonisation[56].

In Belgium three newbuild gas plant are due for commissioning in 2026[57]. There is no known risk to the commissioning timescale but delay to large infrastructure projects is a plausible concern.

Poland has awarded nearly 4 GW of new build gas through the capacity market auction. 1.5-2.5 GW is expected to come online in 2024/25. A remaining 1.4 GW contracted + 0.8 GW assumed for delivery in 2027 is not yet realised.

Derating factors set by this sensitivity are based on a reduction of installed gas fired generation capacity of 6.5 GW across these markets.

German Coal Downside

Germany needs to phase out coal to meet its decarbonisation targets. Among the remaining fleet of coal and lignite plant, it is possible that some of them, especially the small hard-coal plants will decommission earlier. Most major lignite plant require long-term planning and the likelihood of accelerated decommissioning is very limited.

The derating factors set by this sensitivity are based on a 46% scaling in hard coal capacity equivalent to a 5 GW reduction.

German Coal Upside

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[66] e.g. https://www.gesetze-im-internet.de/eeg_2014/__4.html

[67] e.g. https://www.gesetze-im-internet.de/windseeg/__2a.html

[68] e.g. https://www.gesetze-im-internet.de/eeg_2014/__28a.html

[69] e.g. https://urldefense.com/v3/__https:/www.energate-messenger.de/news/229782/offshore-ausbauziele-windbranche-zweifelt-an-machbarkeit__;!!B3hxM_NYsQ!0B3iBwmTsFvAd1xkEUQuQ_0jZe1gAwuAHuATEipYHQ_L8QhSR1qVPJFaAzjwprwohn87hvLkA6lQn__IWH-0BGPpeAx6BulcpfU$

[70] e.g. https://www.bdew.de/energie/beschleunigung-eeg-netzanschluss-umgang-mit-zertifizierungsstau/

[71] https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/photovoltaik-stategie-2023.pdf?__blob=publicationFile&v=4

[72] https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/eckpunkte-einer-windenergie-an-land-strategie.pdf?__blob=publicationFile&v=6

In response to Russia's illegal invasion of Ukraine, Germany has allowed their grid-reserve coal, lignite and mineral oil plants, including those that were expected to unavailable to be reactivated for winter 2022-2023. The plants participation in the Energy market is "voluntary" and will be limited until end-of-emergency status or March 2024. The total eligible capacity is around 11 GW while only a portion of those are confirmed. In view of the current uncertainty in the global energy market Germany may choose to amend the Coal-exit law and delay the phase out.

The derating factors set by this sensitivity are based on a 5 GW uplift in installed hard coal and lignite capacity above the reference case. This is equivalent to a scaling of 124%.

Norway Export

There is growing dependency on Norwegian hydro resources from countries within Europe. This sensitivity considers the uncertainty of these resources being available leading to lower exports from Norway, which would lead to lower imports available for GB[73].

This is modelled such that the derating factors set by this sensitivity assume the unavailability of these resources leads to a reduction to 80% of European Central Case capacity in exports to all external markets.

Celtic Link

Celtic link is expected to begin flowing between Ireland and France in 2026/27 in our European Central Case at 700 MW. This sensitivity considers the uncertainty of this link being unavailable in 2027/28.

Celtic Link + Irish Thermal

This sensitivity combines the uncertainties associated with the Irish adequacy outlook through the Irish thermal sensitivity and the availability of the new Celtic link. We believe that there is sufficient uncertainty associated with both sensitivities to justify combining them.

Table 9: Pan-European modelling runs

Scenarios	Graph name	Description
Base Case	BC	2023 Future Energy Scenarios – Five Year Forecast
Consumer Transformation	CT	2023 Future Energy Scenarios – Consumer Transformation
System Transformation	ST	2023 Future Energy Scenarios – System Transformation
Leading the Way	LW	2023 Future Energy Scenarios – Leading the Way
Falling Short	FS	2023 Future Energy Scenarios – Falling Short

[73] The Norwegian government are formalising a reporting system, introduced in Summer 2022, requiring hydropower producers to report and forecast reservoir levels to ensure that price dynamics fully capture potential risks to security of supply.

5.2.3 PLEXOS Pan-European Model Results

The imports as a percentage of interconnector capacity, from all the pan-European simulations, are shown in Table 10 for 2027/28.

Each of the results tables contains results for the five scenarios and the minimum and maximum sensitivities (i.e., the sensitivities that result in the lowest and highest de-rating factors) from all of the sensitivities for each of the scenarios. Note that the minimum and maximum sensitivities may vary for each scenario. The values that set range for each market are typeset in bold and underlined.

Table 10: Simulation results: 2027/28 imports as percentage of interconnector capacity

	ECR 2022 2026/27 T-4		European Central Case					Minimum Sensitivity					Maximum Sensitivity				
Country	Min.	Max.	BC	CT	ST	LW	FS	BC	CT	ST	LW	FS	BC	CT	ST	LW	FS
Ireland	14	94	69	63	67	65	63	22	22	21	26	**20**	**75**	68	73	69	69
France	30	97	70	80	68	82	66	37	45	37	49	**33**	76	**84**	74	84	72
Belgium	31	95	84	85	82	85	80	33	37	34	39	**30**	87	**88**	85	88	83
Netherlands	51	92	90	94	89	94	91	**41**	47	41	50	44	93	95	93	95	**97**
Denmark	48	91	90	93	88	89	93	61	72	**60**	68	76	94	95	93	92	**97**
Norway	84	100	96	98	95	98	97	74	69	73	**66**	76	96	98	95	**99**	97

5.2.4 Country de-ratings

Results for each of the FES scenarios are shown in Figure 26 to Figure 31 and Table 11 to Table 16. Note that the tables only present results for sensitivities that have a material impact on the derating factors compared to the Base Case results.

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 shift in one country can impact flows from surrounding countries, as can be seen by the impact of French Nuclear capacity reductions on Ireland and Belgium. Modelling flows across Europe for the auction year gives confidence that these interactions have been reflected in the modelled range of de-rating factors.

The following sections focus on flows from each market without reference to the fleet. The fleet view is discussed in more detail in section 5.2.5.

Ireland

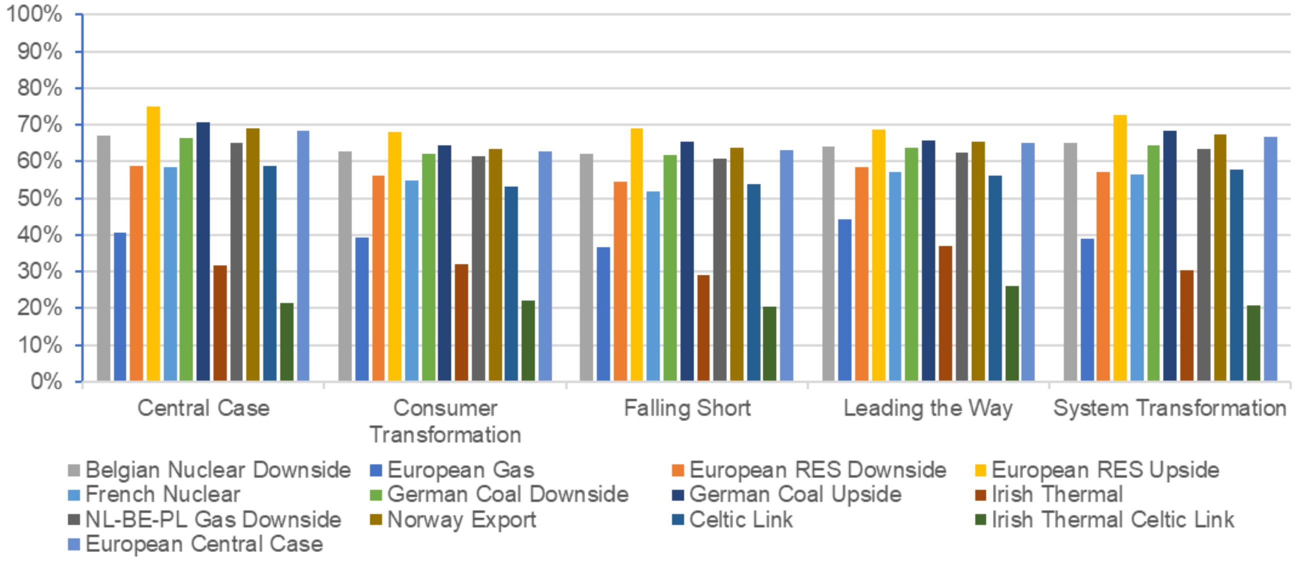
The modelled ranges for Ireland are 20% to 75% for 2027/28.

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 2025[74]. Ireland was modelled as a single price area assuming no restrictions on flows within the all-island system.

In their most recent All-Island Generation Capacity Statement the Irish system operators described it as "a challenging outlook for Ireland with capacity deficits identified during the 10 years to 2031".. Ireland is predicted to benefit from increased interconnector capacity via Greenlink and the Celtic interconnector in the coming years. Nevertheless, generator availability, withdrawal of previously awarded capacity, run hour restrictions and increasing levels of demand are predicted to force the Single Energy Market into a capacity deficit (defined as shortfall against their adequacy standard) in 2027 as well as in preceding and following years.[75]

The results for Ireland show a narrowed range compared to the 2022 ECR. The Ireland thermal sensitivity demonstrates the reduction in interconnector de-rating factor if Ireland continues to be unable to secure enough capacity (or experience higher demands). The Celtic link between Ireland and France, provides additional resilience and there is also a possibility for extra capacity from France to wheel through Ireland.

Figure 26: Irish interconnector de-rating factors 2027/28



[74] https://www.soni.ltd.uk/media/documents/EirGrid_SONI_2022_Generation_Capacity_Statement_2022-2031.pdf

[75] All-Island Generation Capacity Statement 2022-2031, Figure 4.1 October 2022

Table 11: Irish interconnector de-rating factors 2027/28

Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	69	63	63	65	67	
Ireland Thermal	32	32	29	37	31	
European RES upside	75	68	69	69	73	Maximum Sensitivity
European Gas	41	39	37	44	39	
French Nuclear	58	55	52	57	57	
European RES downside	59	56	54	58	57	
Celtic Link	59	53	54	56	58	
Ireland Thermal + Celtic Link	22	22	20	26	21	Minimum Sensitivity

France

The modelled ranges for France are 33% to 84% for 2027/28.

The French market has been affected by the availability of its nuclear in recent years. This has been due to a combination of delays to maintenance requirements resulting from the corona virus pandemic and more recently to the discovery of stress corrosion on piping in several reactors. Additionally, French demand is very weather sensitive, so very cold weather results in demand exceeding domestic generation. As the interconnector capacity with France grows, we may see de-rating factors falling further, particularly if nuclear availability is low. France is well interconnected to other markets in Europe which gives access to excess capacity in these markets. France also tends to be a net exporter to other European markets, and we assume excess capacity in France is used to meet demand in markets within the EU's internal energy market where possible before it is used to meet demand in GB. The French de-rating factor is particularly affected by the French nuclear and the European Gas sensitivities.

Figure 27: French interconnector de-rating factors 2027/28

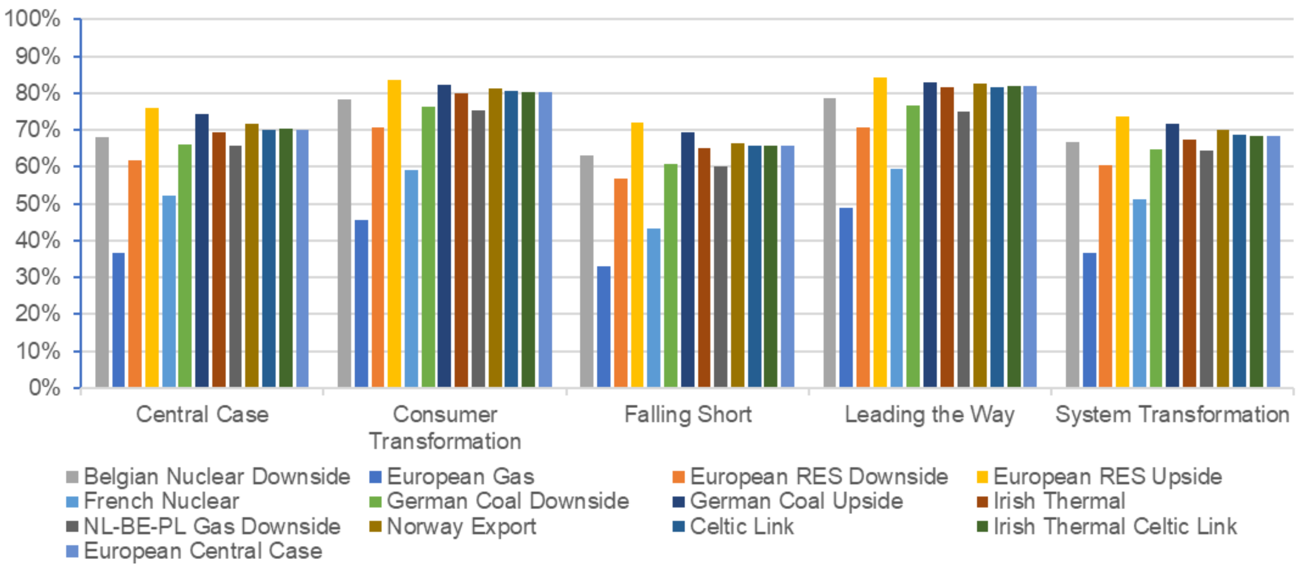


Table 12: French interconnector de-rating factors 2027/28

Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	70	80	66	82	68	
French Nuclear	52	59	43	59	51	
European RES upside	76	84	72	84	74	Maximum Sensitivity
European Gas	37	45	33	49	37	Minimum Sensitivity
Belgian Nuclear downside	68	78	63	79	67	
European RES downside	62	71	57	71	60	
Ireland Thermal	69	80	65	82	68	
Celtic Link	70	81	66	82	69	
Ireland Thermal + Celtic Link	70	80	66	82	68	

Belgium

The modelled ranges for Belgium are 30% to 88% for 2027/28.

Belgium had planned to phase out nuclear power by 2025 but has since delayed that decision for two of its seven reactors until 2035. Doel 4 and Tihange 3 are due to undergo maintenance related outages during winter 2025/26. The Belgium Nuclear sensitivity considers the uncertainty of these units also being unavailable in 2027/28, although this has a relatively small impact on Belgium de-rating factors. The minimum downside is set by the European Gas sensitivity while the maximum upside is set by the European RES and German Coal sensitivities.

Figure 28: Belgium interconnector de-rating factors 2027/28

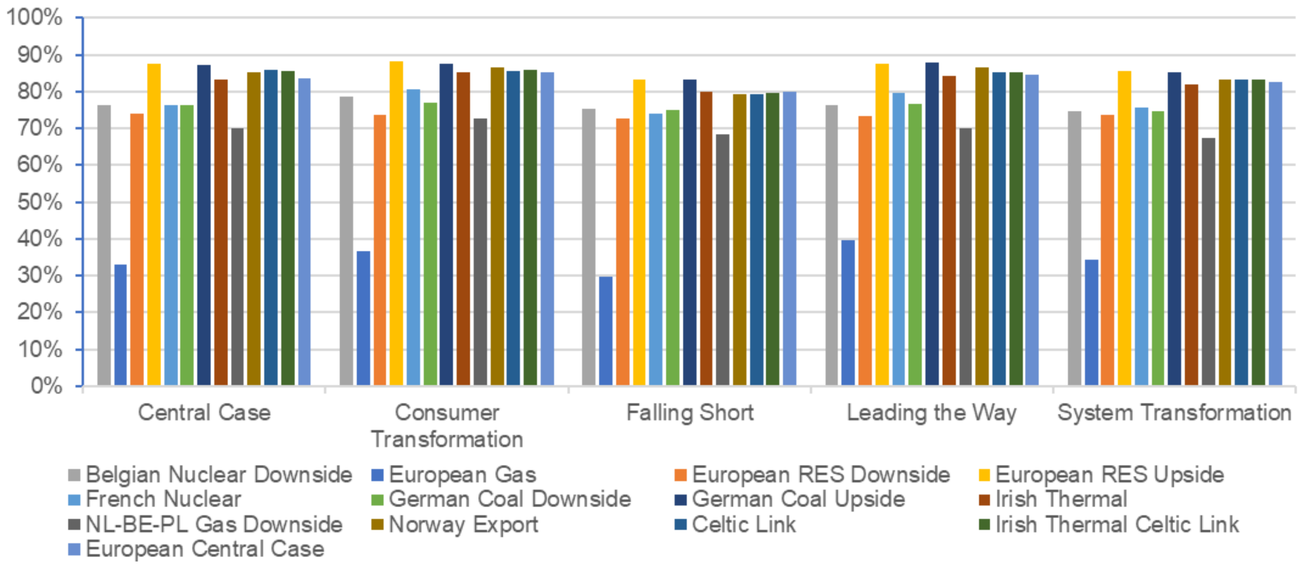


Table 13: Belgium interconnector de-rating factors 2027/28

Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	84	85	80	85	82	
NL-BE-PL Gas Downside	70	73	69	70	67	
European RES upside	87	88	83	88	85	Maximum Sensitivity
European Gas	33	37	30	39	34	Minimum Sensitivity
Belgian Nuclear downside	76	79	75	76	75	
European RES downside	74	74	73	73	74	
French Nuclear	76	81	74	80	76	
German Coal Downside	76	77	75	77	75	
German Coal Upside	87	88	83	88	85	Maximum Sensitivity
Ireland Thermal	83	85	80	84	82	
Celtic Link	86	86	79	85	83	
Ireland Thermal + Celtic Link	85	86	80	85	83	

Netherlands

The modelled ranges for Netherlands are 41% to 97% for 2027/28.

The modelling assumed a firm import capacity of 1000 MW on BritNed 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.

The Netherlands has proven to be adequate in our modelling having sufficient gas generation capacity and interconnection to several large markets. Given the reliance on gas fired generation it is perhaps unsurprising that the European gas sensitivity sets the bottom of the range. Top of the range is set by the European RES upside sensitivity.

Figure 29: Netherlands interconnector de-rating factors 2027/28

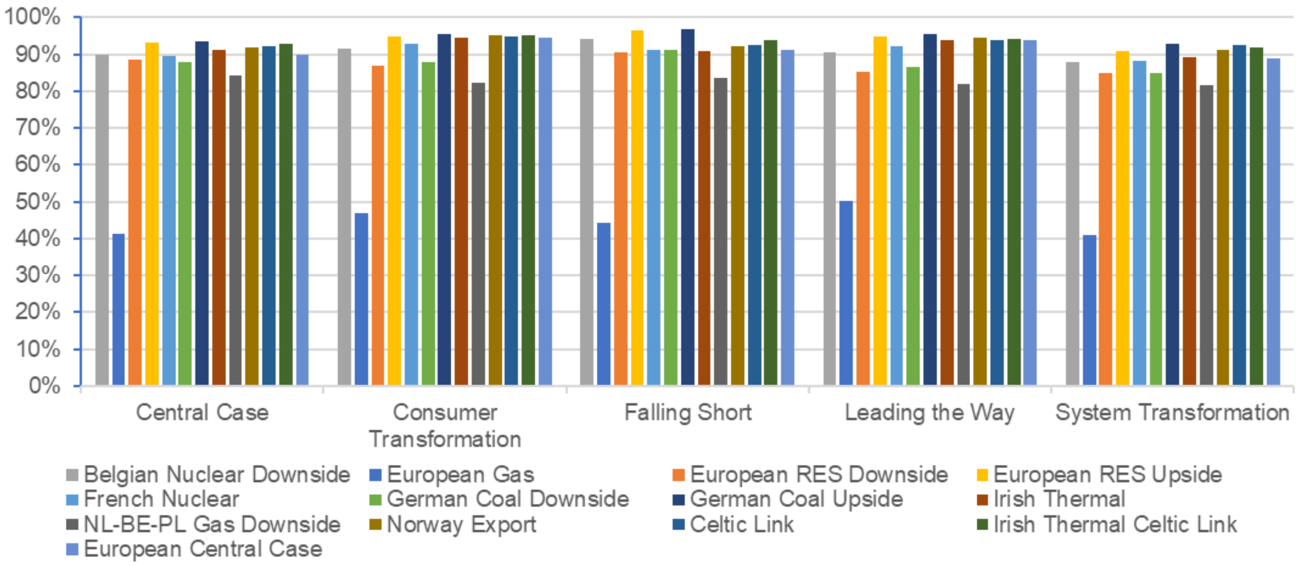


Table 14: Netherlands interconnector de-rating factors 2027/28

Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	90	94	91	94	89	
NL-BE-PL Gas Downside	84	82	84	82	82	
European RES upside	93	95	97	95	91	Maximum Sensitivity
European Gas	41	47	44	50	41	Minimum Sensitivity
Belgian Nuclear downside	90	92	94	90	88	
European RES downside	89	87	91	85	85	
French Nuclear	89	93	91	92	88	
Ireland Thermal	91	95	91	94	89	
Celtic Link	92	95	93	94	93	
Celtic Link + Ireland Thermal	93	95	94	94	92	

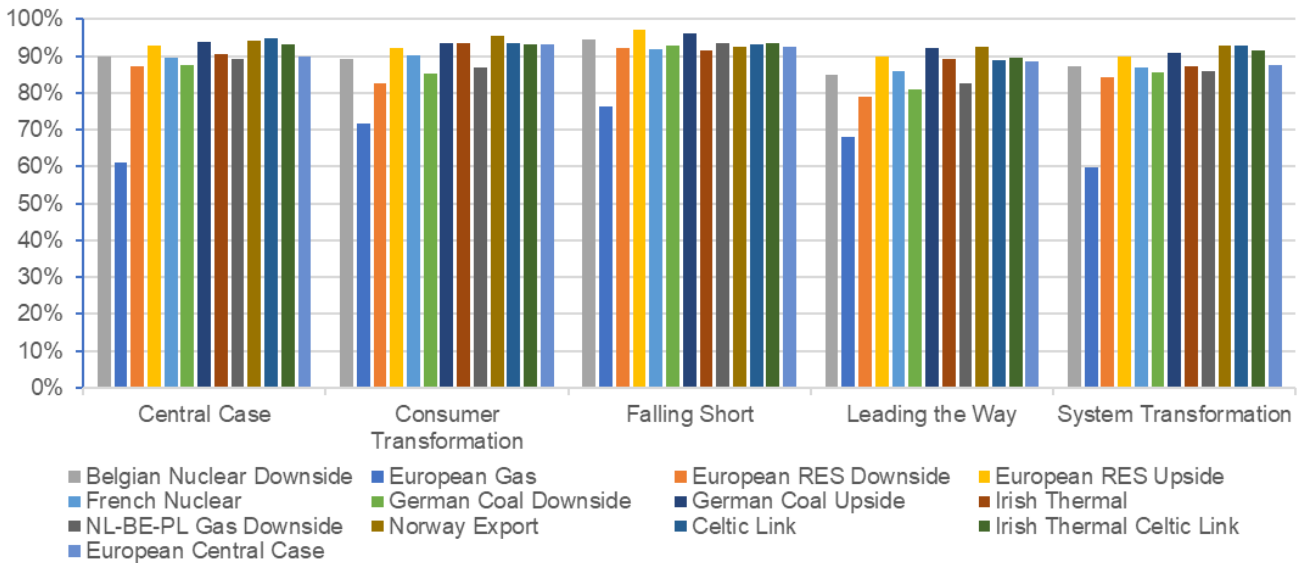
Denmark

The modelled ranges for Denmark are 60% to 97% for 2027/28.

Denmark has a large interconnection capacity compared to its demand and is well supplied by a number of large markets including Norway, Sweden and Germany. There is limited thermal capacity and a large wind fleet that would ordinarily leave a market open to adequacy concerns. However, Denmark is known as a "price taker" because it acts as a transit hub[76]. Our modelling supports this view showing Denmark often importing much more capacity than it requires and exporting the excess, which often includes its own surplus wind capacity.

The results show quite a relatively narrow range of derating factors with European Gas setting the lower bound and European RES upside setting the upper bound. There is some uncertainty for Denmark in that the first interconnector with GB is not expected until 2024 and so we don't have any operational experience of how this link will operate.

Figure 30: Denmark interconnector de-rating factors 2027/28



76 https://ens.dk/sites/ens.dk/files/El/analysis_of_danish_market_report_afry_report_december_2019.pdf

Table 15: Denmark interconnector de-rating factors 2027/28

Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	90	93	93	89	88	
European RES downside	87	83	92	79	84	
European RES upside	93	92	97	90	90	Maximum Sensitivity
European Gas	61	72	76	68	60	Minimum Sensitivity
NL-BE-PL Gas Downside	89	87	94	83	86	
French Nuclear	90	90	92	86	87	
German Coal upside	94	93	96	92	91	
German Coal downside	88	85	93	81	86	
Ireland Thermal	90	94	92	89	87	
Celtic Link	95	93	93	89	93	
Celtic Link + Ireland Thermal	93	93	93	90	92	

Norway

The modelled ranges for Norway are high across all scenarios giving a range of 66% to 99% for 2027/28.

The high interconnector de-rating factors are due to the large volume of hydro capacity in Norway. The lower end of the range demonstrates the potential impact on flows to GB if the availability of resources in Norway leads to a reduction in exports to all markets.

Figure 31: Norway interconnector de-rating factors 2027/28

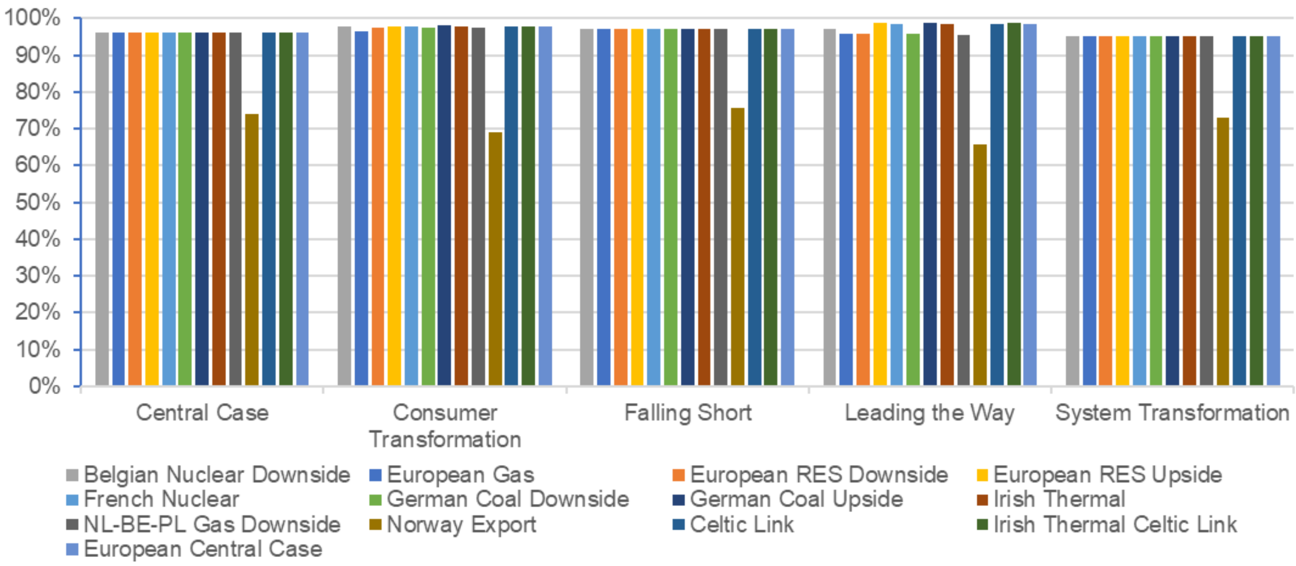


Table 16: Norway interconnector de-rating factors 2027/28

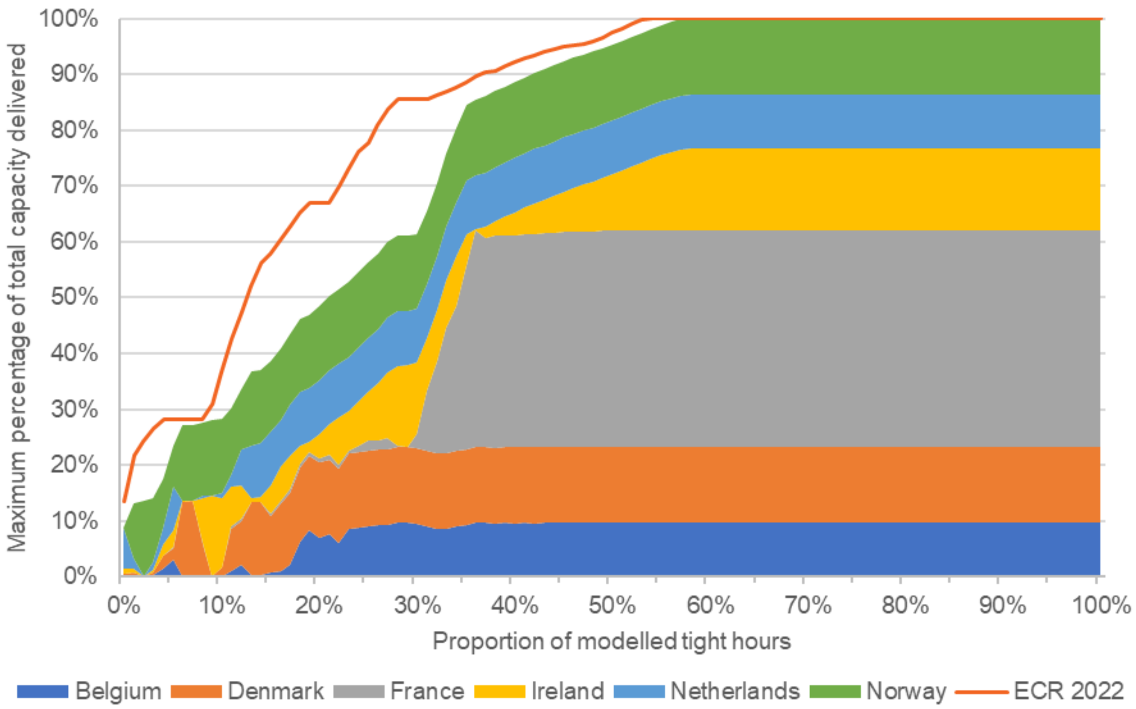
Sensitivity	Base Case	Consumer Transformation	Falling Short	Leading the Way	System Transformation	Note
European Central Case	96	98	97	98	95	
Norway Export	74	69	76	66	73	Minimum Sensitivity
European RES downside	96	97	97	96	95	
European Gas	96	97	97	96	95	
French Nuclear	96	98	97	99	95	Maximum Sensitivity

5.2.5 Whole fleet imports

The distributions of hourly derating factors in each market are highly bimodal with modes centred on zero and one hundred per cent (i.e. interconnectors are either exporting at full capacity or are at float). This result is expected within the modelling framework which simulates economic arbitrage and was also observed in the 2022 ECR.

This view on the "on-off" the nature of interconnector flows raises the question of whether multiple markets have correlated periods when they are not exporting to GB. The chart below shows for the Base Case the proportion of modelled tight hours where a maximum percentage of total interconnected capacity is delivered. For example, 15% of the time, interconnector imports are less than or equal to approximately 40% of the total interconnector capacity. Alternatively, one can view the chart in terms of minimum capacity delivered. For example, 80% of the total capacity is available for around 70% of modelled GB tight hours.

Figure 32: Proportion of modelled tight hours where a maximum percentage of interconnected capacity is available in FES Base Case for the European Central Case



The chart segmentation shows contributions to fleet capacity from individual markets. This provides some additional insight on how tight hours in these markets are correlated with tight periods in GB. The most striking feature is the step change in contributions from France, which provides almost none of its capacity in the first 30% of tightest hours and 100% in the last 70%. The first 30% of tightest hours in GB are extremely highly correlated with tight hours in France. France has a greater correlation of tight hours with GB than any of the other markets.

The further the curve lies towards the top left-hand corner of the chart, the greater the available capacity in tight hours. The shape and initial ascent of the curve is clearly driven by France, both because of the high correlation with GB tight hours but also because of the large proportion of total fleet capacity provided by the French interconnectors.

The orange line depicts the equivalent chart from the 2022 ECR. In this case the curve lies closer towards the top left-hand corner of the chart indicating that there was more fleet capacity available in the tightest hours in our 2022 analysis. However, most of the difference here can be explained by the fact that we have included higher unavailability of the French nuclear fleet in the European Central Case, reflecting recent market observations, whereas in previous years it has mainly been modelled as a sensitivity.

At minimum the other markets are able to provide a fraction of capacity during approximately 95% of tight hours and it is notable that Norway is able to supply a majority of capacity for all tight hours.

The Irish interconnectors are able to provide a level of capacity during approximately 95% of all tight hours, however they are only able to provide full capacity during approximately 40% of tight hours. This indicates high correlation between tight hours in GB and Ireland.

Overall, the modelling results suggest that we can rely on full fleet imports during 40% of modelled tight hours within our Base Case.

As capacity in Europe is reduced in sensitivities, European markets will share more tight hours in which they are unable to export, and this will be reflected as lower availability of total interconnected capacity in a greater proportion of tight hours. This will manifest in the chart as shallower ascents towards 100% available fleet capacity and in the most extreme cases, less than full capacity availability in all modelled tight hours.

Summary

The interconnector de-rating factor ranges have narrowed since last year for most countries in our study. This represents both a reduction in the upside range and the downside from sensitivities included this year. The ranges have been selected from the highest and lowest value from the results table for each country. The maximum is generally set by the European RES upside sensitivity in all cases. The minimum comes from European Gas reduction or Irish thermal reduction.

It should be noted that while the events that may lead to a reduction in gas generating capacity are possible, the justifications for these sensitivities have little historical precedent. Therefore, the actual amount of gas generating capacity removed from the scenarios to create the sensitivities is uncertain. Our modelling is trying to reflect the range of potential uncertainty four years from now.

Importantly, we have also seen a reduction in the Base Case for France - which has the highest total level of interconnection with Britain. The impact of this on the fleet is seen in Figure 32 where France dominates the imports. This reflects the risks associated with lower nuclear fleet availability observed in several recent winters. Our European Central Case now reflects this lower availability in the market.

Ireland has also got a lower Base Case derating. Future capacity is uncertain in Ireland and our European scenario reflects the latest all-island adequacy report.

In the north of Europe, Norway is generally well supplied through its natural hydro generation. However, the availability of these resources could lead to lower exports to all markets, impacting available flows to GB. Denmark has high derating factors across many of the sensitivities reflecting its position as a price taker from its neighbouring markets.[77] There is capacity to export to Germany and the Netherlands alongside Britain due to imports from Norway and Sweden and high levels of wind capacity. Only when Europe is stressed as a whole do we see a reduction in flows to Britain.

The Netherlands has sufficient gas capacity and is resilient to many sensitivities due to this reliable generation mix and interconnection to neighbouring markets.

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain, which we don't expect to be a material issue at winter peak. Adjustments for technical reliability will be made by DESNZ. The ranges for each country are shown in Table 17. Although in some cases the ranges are wide, we consider them to be credible given the uncertainty on future generation capacity in Europe.

We have highlighted the risk of interconnector bi-modality in our analysis, following on from the insight in the 2022 ECR when this was shown for the first time. There is also a correlation risk associated with the interconnectors providing a ”tail-risk” profile when the fleet is considered as whole. This is an area of our modelling that we expect to develop further ahead of the 2024 ECR. .

Table 17: De-rating factor ranges by country for 2027/28

Country	Minimum	Maximum
Ireland	20	75
France	33	84
Belgium	30	88

[77] https://ens.dk/sites/ens.dk/files/El/analysis_of_danish_market_report_afry_report_december_2019.pdf

Netherlands	41	97
Denmark	60	97
Norway	66	99

6 Results and Recommendation for T-1 Auction for delivery in 2024/25

Our recommendation for the target capacity for the T-1 auction for delivery in 2024/25 is **7.4 GW**. For the case ahead of the 2024/25 winter where no future unknown non-delivery has yet materialised (similar to the ESO's Winter Outlook Reports[78]), this recommendation corresponds to a Base Case LOLE of 0.3 hours/year and a de-rated margin of 3.8 GW (6.3%), while if around 3 GW of future unknown non-delivery were to materialise then by the 2024/25 delivery year the Base Case LOLE would be 2.4 hours/year[79]. The recommended capacity in this report will not necessarily be the capacity auctioned – this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification.

This chapter presents the detailed modelling results to support our recommendation of 7.4 GW. Further information on potential capacity requirements in the period until 2037/38 can be found in Section 4.9.

6.1 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 Falling Short (FS)
- 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)

[78] https://www.nationalgrideso.com/research-and-publications/winter-outlook

[79] The de-rated margin assuming around 3 GW future unknown non-delivery materialises for 2024/25 would be 2.1 GW 3.5%

- Non-Delivery (NON-DEL): Up to 4000 MW in 400 MW increments[80]
- Over-Delivery (OVER DEL): Up to 3600 MW in 400 MW increments

6.2 Results

Table 18 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 amount of 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 which is when capacity providers that secured an agreement covering delivery year 2024/25 from a previous auction can no longer meet their obligations. This known non-delivery totals 0.8 GW (de-rated) since the 2020 ECR (which contained our recommendation for the T-4 auction for delivery in 2024/25).

Additionally, we estimate future unknown non-delivery by modelling a 6% average non-delivery probability in our Base Case, FES scenarios and sensitivities (for more details, see discussion of methodology implemented via PTE60 Phase 2 in Section 3.4.2). Non-delivery in the FES scenarios reflect uncertainty of capacity providers that may be at risk of not meeting their obligations. There is 0.3 GW of additional non-delivery assumed in the FS scenario; we have therefore reduced the average non-delivery probability of the FS scenario to 5.5%. This can be seen in Table 18 where the previously contracted capacity for these scenarios is either above or below the Base Case value. The modelled future unknown non-delivery is shown in the final column: this is the increase in total capacity required to meet 3 hours LOLE and comprises an increase in capacity to secure to offset the non-delivery and an increased wind EFC of around 0.4 GW depending on scenario or sensitivity.

Furthermore, all scenarios and sensitivities include 0.4 GW over-delivery for 2024/25 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 of the 2022 ECR) 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.

[80] Note that future unknown non-delivery is already modelled in all scenarios and sensitivities via an average non-delivery probability. The non-delivery sensitivities are used to provide 0.4GW increments for the LWR outcome. In the LWR analysis, we have only included non-delivery sensitivities that fall within the range of other scenarios and sensitivities modelled since such sensitivities are not allowed to set the range of the LWR calculation (see Section 4.8.4). As a result, non-delivery sensitivities above 2800 MW are excluded in this chapter.

Table 18: Modelled de-rated capacities and peak demands – 2024/25

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW) in sensitivity	Total derated capacity (GW)	ACS Peak (GW)	Modelled Non Delivery (GW)
Leading the Way	LW	2.4	59.2	45.7	0.0	61.7	55.1	3.3
Over Delivery Sensitivity: 3600	BC - 3600	3.4	62.2	45.8*	3.6	65.7	58.5	3.5
Warm Winter	BC_WARM	3.8	59.3	45.8	0.0	63.1	58.5	3.2
Over Delivery Sensitivity: 3200	BC - 3200	3.8	61.8	45.8*	3.2	65.7	58.5	3.5
Over Delivery Sensitivity: 2800	BC - 2800	4.2	61.4	45.8*	2.8	65.7	58.5	3.5
Over Delivery Sensitivity: 2400	BC - 2400	4.6	61.0	45.8*	2.4	65.7	58.5	3.5
Over Delivery Sensitivity: 2000	BC - 2000	5.0	60.6	45.8*	2.0	65.7	58.5	3.5
Over Delivery Sensitivity: 1600	BC - 1600	5.4	60.2	45.8*	1.6	65.7	58.5	3.5
Low Demand	BC_LOW_DEMAND	5.7	58.5	45.8	0.0	64.1	57.2	3.3
Consumer Transformation	CT	5.7	58.8	45.8	0.0	64.5	57.5	3.3
Over Delivery Sensitivity: 1200	BC - 1200	5.8	59.8	45.8*	1.2	65.7	58.5	3.5
Over Delivery Sensitivity: 800	BC - 800	6.2	59.4	45.8*	0.8	65.7	58.5	3.5
High Availability	BC_HIGH_AVAIL	6.4	59.0	46.3	0.0	65.4	58.5	3.3
Over Delivery Sensitivity: 400	BC - 400	6.6	59.0	45.8*	0.4	65.7	58.5	3.5
Base Case	BC	7.0	58.6	45.8	0.0	65.7	58.5	3.5
System Transformation	ST	7.2	58.7	45.8	0.0	65.9	58.8	3.5
Non Delivery Sensitivity: -400	BC +400	7.4	58.2	45.8*	-0.4	65.7	58.5	3.5
Low Availability	BC_LOW_AVAIL	7.8	57.9	45.2	0.0	65.8	58.5	3.3
Non Delivery Sensitivity: -800	BC +800	7.8	57.8	45.8*	-0.8	65.7	58.5	3.5
Non Delivery Sensitivity: -1200	BC +1200	8.2	57.4	45.8*	-1.2	65.7	58.5	3.5
Cold Winter	BC_COLD	8.4	58.0	45.8	0.0	66.4	58.5	3.4
Non Delivery Sensitivity: -1600	BC +1600	8.6	57.0	45.8*	-1.6	65.7	58.5	3.5
Non Delivery Sensitivity: -2000	BC +2000	9.0	56.6	45.8*	-2.0	65.7	58.5	3.5
Non Delivery Sensitivity: -2400	BC +2400	9.4	56.2	45.8*	-2.4	65.7	58.5	3.5
High Demand	BC_HIGH_DEMAND	9.6	58.7	45.8	0.0	68.3	61.0	3.6
Non Delivery Sensitivity: -2800	BC +2800	9.8	55.8	45.8*	-2.8	65.7	58.5	3.5
Falling Short	FS	10.4	58.4	45.5	0.0	68.8	61.8	3.2

** 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 is accounted for in a separate column.*

N.B Total derated capacity (GW) = Capacity to Secure (GW) + Outside Capacity Market (GW). ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2024/25 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 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, including the T-4 auction for 2020/21, is now around 0.5 GW lower than has been contracted (which was also noted in the 2020 ECR[81] that contained our capacity to secure recommendation for the 2024/25 T-4 auction). 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 0.4 GW lower than was previously contracted. These two changes combined with the known non-delivery (0.8 GW) have effectively reduced the estimate of the previously contracted capacity for 2024/25 in the Base Case from the reported[82] figure of around 47.6 GW to around 45.8 GW – a shortfall of 1.8 GW that needs to be secured again. If the modelled unknown non-delivery materialises, this could reduce the previously contracted figure even more from the current estimate of 45.8 GW.

[81]https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202020.pdf#search=electricity%20capacity%20report

[82] See page 7 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2026-27%20Final%20Auction%20Results%20Report%20v1.0.pdf

The LW and FS scenarios define the extremes of the capacity to secure range for 2024/25 (2.4 GW to 10.4 GW).

6.3 Recommended Capacity to Secure

The results in Table 18 show there is a wide range in the capacity required to meet 3 hours LOLE from 2.4 GW to 10.4 GW. The LW scenario and FS scenario define the extremes of the range.

We use the Least Worst Regret (LWR) methodology to select one of the values from Table 18 as our recommended target capacity for the T-1 auction for delivery in 2024/25. 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 18, there will be a worst-case outcome. For example. if we select the option needing 10.4 GW then the worst-case outcome would be if 2.4 GW was actually needed. The LWR[83] 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.8.

The outcome of the LWR calculation is a recommended capacity to secure of **7.4 GW**. This is the capacity associated with the 0.4 GW non-delivery sensitivity. This outcome excludes any capacity secured for 2024/25 in earlier auctions assumed in the Base Case.

Figure 33 shows the regret costs for the FES scenarios and the Base Case. The LWR capacity outcome and LWR cost are also shown. The LWR outcome is the capacity (to the nearest 0.4GW) that marks the intersection of the regret costs for the two cases at the extremes of the LWR range (the LW and FS scenarios).

[83] 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).

Figure 33: Regret Costs for scenarios and selected sensitivities – 2024/25

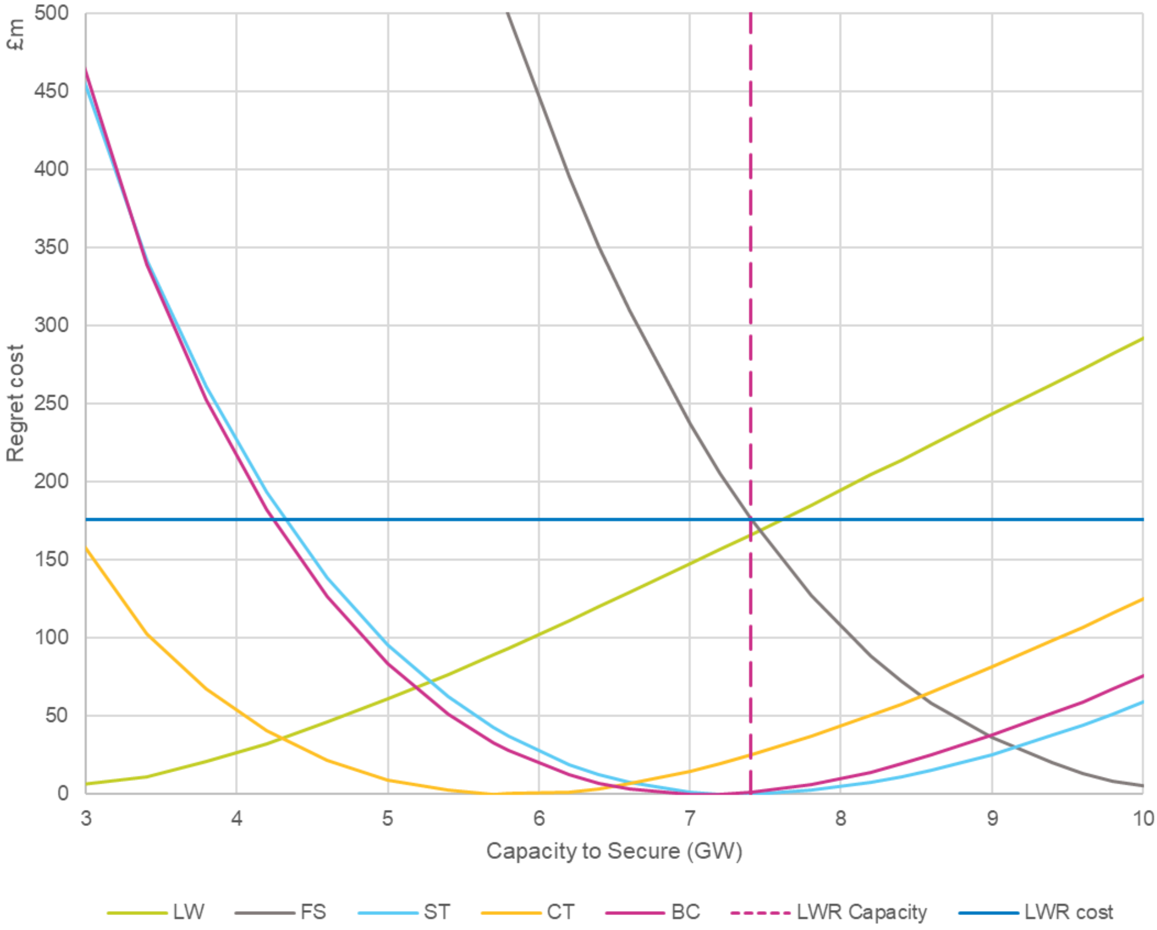
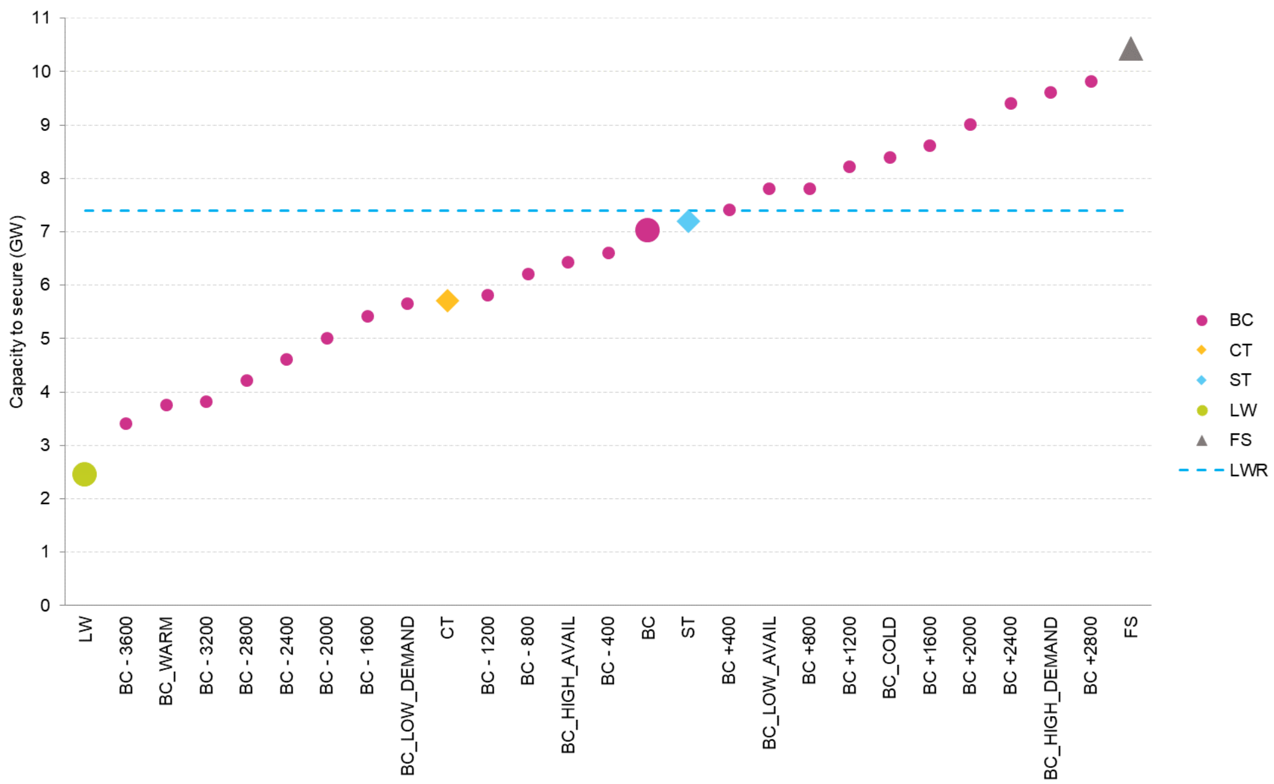


Figure 34 illustrates the full range of potential capacity requirements and identifies the LWR outcome (7.4 GW). Scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. The Falling Short scenario has a higher requirement than the other scenarios, mainly due to a higher peak demand. The Leading the Way scenario has a lower requirement due to a much lower peak demand.

Figure 34: LWR outcome and other cases modelled comparison – 2024/25



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

If we had used the same approach as in the 2022 ECR (and other previous ECRs), with no modelled unknown non-delivery in the scenarios and sensitivities, but with a range of non-delivery sensitivities up to 7.2 GW (see Table 5 “Total” row, rounded to nearest 0.4GW), then the target capacity for delivery in 2024/25 would have been 7.9 GW (0.5 GW higher), within the uncertainty range of the LOLE calculation. This shows that the result produced by the two non-delivery modelling approaches is broadly similar.

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 2024/25 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 34 shows that the outcome of the LWR calculation covers 17 of the 28 cases.

6.3.2 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. This value will be 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 ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Government (either upon confirming auction parameters to the 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 the 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 the 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 T-1 auction for delivery in 2024/25 could be:

- 7.4 GW - ***x*** - ***y*** - ***z***.

*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.

6.3.3 Comparison with T-4 for 2024/25 recommendation

In our 2020 ECR, we recommended a capacity to secure for 2024/25 of 41.6 GW derived from the Base Case 0.8GW non-delivery sensitivity. Following pre-qualification, the target for 2024/25 delivery was increased by the Secretary of State to 42.1 GW with 2.0 GW set aside for the T-1 auction for delivery in 2024/25. The 0.5 GW (net) of adjustments made to the T-4 auction for delivery in 2024/25 target comprised of:

- 0.15 GW increase due to autogeneration assumed to be outside of the CM that prequalified
- 0.35 GW due to additional known non-delivery

In general, when compared to the analysis for 2024/25 in the 2020 ECR that ultimately led to the 2.0 GW set aside by the Secretary of State for the T-1 auction, the 2023 ECR LWR outcome for 2024/25 is 5.4 GW higher than the 2.0 GW set aside. This difference is the result of the following increases and decreases.

The increases total 7.4 GW:

- An increase of 0.4 GW resulting from the LWR outcome (set by the 0.4 GW non-delivery sensitivity) that is higher than the Base Case requirement
- Known non-delivery since the 2020 Base Case, totalling 0.8 GW in 2024/25 (see Section 6.2).
- The contracted conventional capacity for 2024/25 from previous auctions being 0.4 GW greater than the de-rated TEC (see Section 6.2). Note that there was approximately no change in estimated de-rated storage awarded multi-year contracts from the T-4 auction for

delivery in 2020/21 onwards (0.5 GW reduction in the 2023 ECR compared to a 0.5 GW reduction in the 2020 ECR for 2024/25).

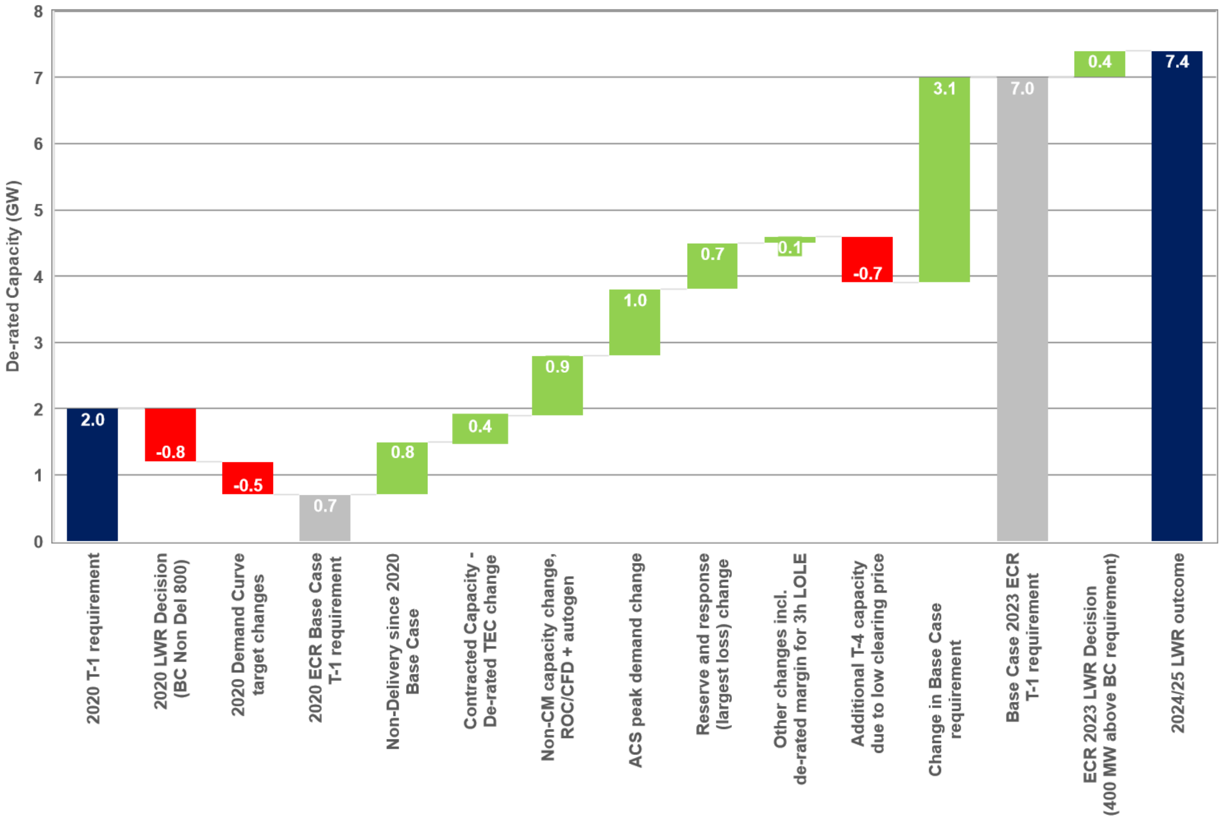
- A 0.9 GW increase resulting from lower non-CM renewable capacity and non-CM autogeneration (see Table 23 for breakdown). This is largely comprised of lower contributions at peak from wind, biomass, landfill gas and from other small-scale capacity. Note that the non-CM autogeneration in the 2023 ECR includes the 0.4 GW over-delivery assumed in the Base Case (see Section 6.2)
- A 1.0 GW increase due to higher peak demand in 2024/25 compared to the 2020 Base Case (see section on peak demand changes below).A 0.7 GW increase in reserve for largest infeed loss compared to the 2020 Base Case (see development project in Section 3.4.2).
- A 0.1 GW increase due to other changes (including change in de-rated margin required for 3 hours LOLE compared to the 2020 Base Case).
- A 3.1 GW increase due to modelled unknown non-delivery probability of 6% based on the average non-delivery post final T-1 auction target over the last 5 winters (see Section 3.4.2).

The decreases total 2.0 GW:

- A 0.8 GW reduction from deducting the differential of the 2020 ECR LWR outcome (set by the 0.8 GW non-delivery sensitivity) compared to the 2020 ECR Base Case requirement.
- 0.5 GW net decrease relating to the demand curve adjustments made in 2020 following prequalification for the T-4 auction (see above for more details). These adjustments are no longer relevant for the T-1 auction as the prequalification for the T-1 auction has not yet taken place and the 2023 Base Case generation assumptions are different to the 2020 Base Case assumptions.
- A reduction in requirement from over-securing in the T-4 auction for delivery in 2024/25 by 0.7 GW due to a low clearing price.

Figure 35, shows how the original 2.0 GW set aside for the T-1 auction for delivery in 2024/25 (derived from the 2020 Base Case 0.8 GW non-delivery sensitivity) has changed into a LWR outcome of 7.4 GW (derived from the 2023 Base Case 0.4 GW non-delivery sensitivity) as a result of the 5.4 GW net increase described above.

Figure 35: Comparison with original T-1 requirement for 2024/25 (de-rated)



Note: intermediate totals in grey above show requirements for 2020 Base Case and 2023 Base Case

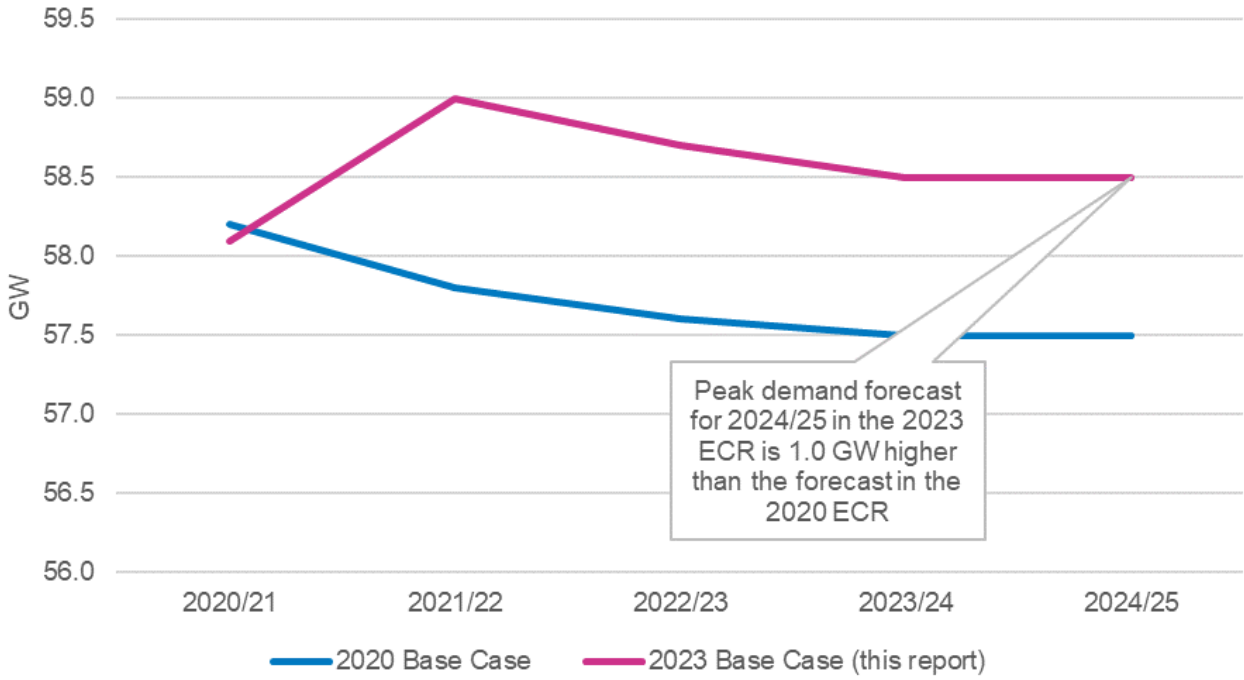
As highlighted above, since the 2020 ECR, the peak demand for 2024/25 has increased by 1.0 GW (from 57.5 GW to 58.5 GW). Figure 36 compares the underlying ACS peak demand in the 2023 Base Case (2023 BC) to the underlying ACS peak demand in the 2020 Base Case (2020 BC) over the period from 2020/21 to 2024/25. The 2023 Base Case peak demand forecast for 2024/25 is 1 GW higher than the 2020 Base Case. This increase is mainly due to building efficiency improvements occurring more slowly than expected, offset by slower electrification of heat than expected. Though demand is suppressed by a large spike in energy prices and a cost of living squeeze, consumers protect demand during peak periods.

The letter[84] written to Ofgem under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology and the steps taken to taken to improve the peak demand forecast.

[84] To be published at the same time as the ECR at https://www.emrdeliverybody.com/cm/home.aspx

The letter published in 2020 is available at https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Demand%20Incentive%20Letter%202020.pdf

Figure 36: Peak Demand Comparison (2023 ECR v 2020 ECR)



6.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery and over-delivery 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 19.

Table 19: Sensitivity of T-1 LWR outcome to scenarios / sensitivities included in LWR

Sensitivities added or removed	2024/25 outcome
Standard range	7.4
Include additional 4.0 GW over-delivery sensitivity	7.4
Remove Leading the Way scenario	7.8
Remove Falling Short scenario[85]	7.4
Include additional sensitivity 3.6 GW above the Base Case requirement	7.8

Removing the lowest target capacity case (Leading the Way) increases the LWR outcome by 0.4 GW. Adding a higher target capacity case (3.6 GW above the Base Case) also increases the

[85] Assuming that the non-delivery sensitivities are not able to set the upper bound of the range of the LWR calculation (see Section 3.5)

LWR outcome by 0.4 GW. No other single cases affect the LWR outcome. For example, adding additional over-delivery cases has no impact on the LWR outcome as the requirement of the LW scenario is below the requirements of the over-delivery cases.

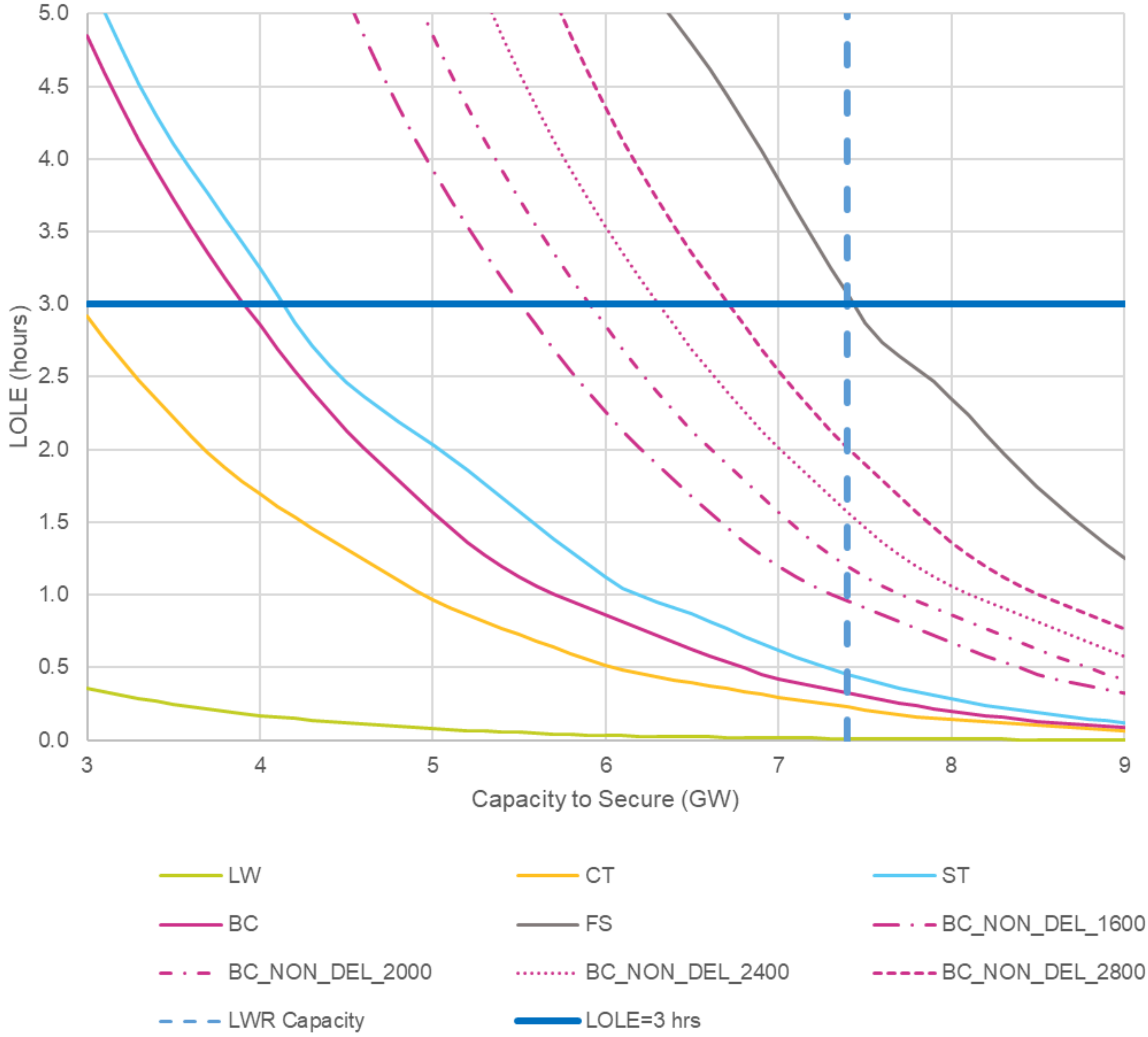
We consider the outcome of the LWR calculation to be suitably robust and that the choice of scenarios and sensitivities included are well-justified as set out in Chapter 4.

6.3.5 Sensitivity of LOLE to T-1 Capacity to Secure

In the 2023 ECR, the recommended capacity to secure corresponds to a LOLE for the Base Case with 6% average future unknown non-delivery of 2.4 hours or 0.3 hours for a Base Case assuming no future unknown non-delivery. To help decision makers to understand the sensitivity of LOLE to the target capacity chosen for the T-1 auction, we have included Figure 37 which illustrates how the LOLE for the scenarios and highest non-delivery sensitivities varies with capacity to secure. We have not included all of the sensitivities on the chart to avoid overcrowding but the other sensitivities have LOLE values below the non-delivery sensitivities shown (the values for all scenarios and sensitivities are in the ECR Data Workbook). The values shown have been adjusted to show the LOLE assuming no modelled unknown non-delivery to enable comparison with the equivalent chart in the 2022 ECR.

Reducing the capacity to secure to 5.5 GW would mean that the LOLE for the FS scenario and the sensitivities shown would be at 3 hours or above, while a capacity to secure of 7.4 GW would keep the LOLE around 3 hours or below for the sensitivities shown and the Falling Short scenario. The LOLE for the Base Case is 0.3 hours for the recommended capacity to secure (7.4 GW) – this would increase to 1.0 hours for a capacity to secure of 5.7 GW and reduce to 0.1 hours for a capacity to secure of 9.0 GW.

Figure 37: Sensitivity of LOLE to Capacity to Secure assuming no non-delivery – 2024/25



7 Results and Recommendation for T-4 Auction for delivery in 2027/28

Our recommendation for the target capacity for the T-4 auction for delivery in 2027/28 is 44.5 GW. For the case ahead of the 2027/28 winter where no future unknown non-delivery has yet materialised (similar to the ESO's Winter Outlook Reports[86]), this recommendation corresponds to a Base Case LOLE of 0.3 hours/year and a de-rated margin of 4.4 GW or 7.1%, while if around 3 GW of future unknown non-delivery were to materialise then by the 2027/28 delivery year the Base Case LOLE would be 2.0 hours/year[87]. The recommended capacity in this report will not necessarily be the capacity auctioned – this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification.

This chapter presents the detailed modelling results to support our recommendation of 44.5 GW. Further information on capacity requirements in years out to 2037/38 can be found in Section 4.9.

7.1 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 Falling Short (FS)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): Up to 4400 MW in 400 MW increments[88]
- Over-Delivery (OVER DEL): Up to 4000 MW in 400 MW increments

[86] https://www.nationalgrideso.com/research-and-publications/winter-outlook

[87] The de-rated margin assuming around 3 GW future unknown non-delivery materialises for 2027/28 would be 2.5 GW 4.0%

[88] Note that future unknown non-delivery is already modelled in all scenarios and sensitivities via an average non-delivery probability. The non-delivery sensitivities are used to provide 0.4GW increments for the LWR outcome. In the LWR analysis, we have only included non-delivery sensitivities that fall within the range of other scenarios and sensitivities modelled since such sensitivities are not allowed to set the range of the LWR calculation (see Section 4.8.4).

7.2 Results

All cases consider known non-delivery where capacity providers that secured an agreement covering delivery year 2027/28 from a previous auction can no longer meet their obligations. This known non-delivery totals around 0.8 GW (de-rated) since the 2022 ECR. Additionally, we estimate future unknown non-delivery by modelling a 6% average non-delivery probability in our Base Case, FES scenarios (except Falling Short) and the demand and weather sensitivities representing the average non-delivery over the past 5 years since the T-1 auction target was finalised (for more details, see discussion of methodology implemented via PTE60 phase 2 in Section 3.5). For Falling Short, we have modelled a lower average non-delivery probability (5%) since the scenario already assumed an additional 0.9 GW of future unknown non-delivery. The non-delivery and over-delivery sensitivities represent changes away from the Base Case that assumed 6% average non-delivery. Our Base Case also assumes no new nuclear units in 2027/28 and that biomass conversion units are eligible to participate in the capacity auction for 2027/28 following the end of RO/CFD support.

The results also reflect our latest view of de-rating factors and TEC values for CM units as we described in Section 6.2. In particular, our estimate of the fleet average EFC of storage awarded multi-year agreements covering 2027/28 from previous CM auctions is now around 0.3 GW lower than has been contracted which is offset by a 0.3 GW increase in de-rated capacity for other technologies (primarily due to the EFC for wind capacity with CM agreements being higher than their auction de-rating factors). These net changes combined with the known non-delivery (0.8 GW) has reduced the estimate of the previously contracted capacity for 2027/28 in the Base Case from the reported[89] figure of just under 13.8 GW to just under 13.0 GW – a shortfall of 0.8 GW that needs to be secured again.

Table 20 shows the de-rated capacity required to meet the Reliability Standard of 3 hours LOLE for each scenario and sensitivity modelled accounting for non-delivery. 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. The modelled unknown future non-delivery is shown in the final column: this is the increase in total capacity required to meet 3 hours LOLE and comprises an increase in capacity to secure to offset the non-delivery and an increased wind EFC of around 0.2 GW depending on scenario or sensitivity.

[89] See page 10 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2026-27%20Final%20Auction%20Results%20Report%20v1.0.pdf

Table 20: Modelled de-rated capacities and peak demands - 2027/28

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)	Modelled Non Delivery (GW)
Leading the Way	LW	35.4	29.3	12.9	0.0	64.7	57.2	2.8
Over Delivery Sensitivity: 4400	BC - 4400	39.3	29.2	13*	4.4	68.5	60.9	3.4
Over Delivery Sensitivity: 4000	BC - 4000	39.7	28.8	13*	4.0	68.5	60.9	3.4
Over Delivery Sensitivity: 3600	BC - 3600	40.1	28.4	13*	3.6	68.5	60.9	3.4
Warm Winter	BC_WARM	40.1	25.8	13.0	0.0	66.0	60.9	3.2
Over Delivery Sensitivity: 3200	BC - 3200	40.5	28.0	13*	3.2	68.5	60.9	3.4
Over Delivery Sensitivity: 2800	BC - 2800	40.9	27.6	13*	2.8	68.5	60.9	3.4
Consumer Transformation	CT	41.0	27.2	13.0	0.0	68.2	60.4	3.0
Over Delivery Sensitivity: 2400	BC - 2400	41.3	27.2	13*	2.4	68.5	60.9	3.4
Over Delivery Sensitivity: 2000	BC - 2000	41.7	26.8	13*	2.0	68.5	60.9	3.4
System Transformation	ST	41.7	26.3	13.0	0.0	68.0	60.4	3.3
Over Delivery Sensitivity: 1600	BC - 1600	42.1	26.4	13*	1.6	68.5	60.9	3.4
Over Delivery Sensitivity: 1200	BC - 1200	42.5	26.0	13*	1.2	68.5	60.9	3.4
Low Demand	BC_LOW_DEMAND	42.9	24.8	13.0	0.0	67.6	60.1	3.4
Over Delivery Sensitivity: 800	BC - 800	42.9	25.6	13*	0.8	68.5	60.9	3.4
Over Delivery Sensitivity: 400	BC - 400	43.3	25.2	13*	0.4	68.5	60.9	3.4
Base Case	BC	43.7	24.8	13.0	0.0	68.5	60.9	3.4
Non Delivery Sensitivity: -400	BC +400	44.1	24.4	13*	-0.4	68.5	60.9	3.4
Non Delivery Sensitivity: -800	BC +800	44.5	24.0	13*	-0.8	68.5	60.9	3.4
Non Delivery Sensitivity: -1200	BC +1200	44.9	23.6	13*	-1.2	68.5	60.9	3.4
Cold Winter	BC_COLD	45.0	24.3	13.0	0.0	69.2	60.9	3.5
Non Delivery Sensitivity: -1600	BC +1600	45.3	23.2	13*	-1.6	68.5	60.9	3.4
Non Delivery Sensitivity: -2000	BC +2000	45.7	22.8	13*	-2.0	68.5	60.9	3.4
Non Delivery Sensitivity: -2400	BC +2400	46.1	22.4	13*	-2.4	68.5	60.9	3.4
Non Delivery Sensitivity: -2800	BC +2800	46.5	22.0	13*	-2.8	68.5	60.9	3.4
Non Delivery Sensitivity: -3200	BC +3200	46.9	21.6	13*	-3.2	68.5	60.9	3.4
High Demand	BC_HIGH_DEMAND	47.0	24.8	13.0	0.0	71.8	64.2	3.6
Non Delivery Sensitivity: -3600	BC +3600	47.3	21.2	13*	-3.6	68.5	60.9	3.4
Non Delivery Sensitivity: -4000	BC +4000	47.7	20.8	13*	-4.0	68.5	60.9	3.4
Non Delivery Sensitivity: -4400	BC +4400	48.1	20.4	13*	-4.4	68.5	60.9	3.4
Falling Short	FS	48.2	23.3	12.1	0.0	71.4	64.4	3.0

** 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 is accounted for in a separate column*

N.B Total derated capacity (GW) = Capacity to Secure (GW) + Outside Capacity Market (GW). ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2027/28 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.

7.3 Recommended Capacity to Secure

Table 20 shows there is a wide range in the capacity required to meet 3 hours LOLE from 35.4 GW to 48.2 GW. The LW scenario and FS scenario define the extremes of the range. We use the Least Worst Regret (LWR) methodology described in Section 6.3 to select one of the values from Table 20 as our recommended target capacity for the T-4 auction for delivery in 2027/28.

The outcome of the LWR calculation is a capacity to secure of **44.5 GW**. This is the capacity associated with the 0.8 GW non-delivery sensitivity – this sensitivity assumes an additional 0.8 GW of future unknown non-delivery in the Base Case above the average level modelled in the Base Case. This outcome excludes any capacity secured for 2027/28 in earlier auctions assumed in the Base Case.

Figure 38 shows the regret costs for the two cases that define the extremes of the LWR range (LW and FS scenarios), the other FES and Base Case and the sensitivity with a requirement 0.8 GW above the Base Case that sets the LWR outcome. The LWR capacity outcome and LWR cost are also shown. The LWR outcome is the closest capacity requirement value to the capacity that marks the intersection of the regret costs for the two cases at the extremes of the LWR range (LW and FS scenarios).

Figure 38: Regret Costs for scenarios and selected sensitivities – 2027/28

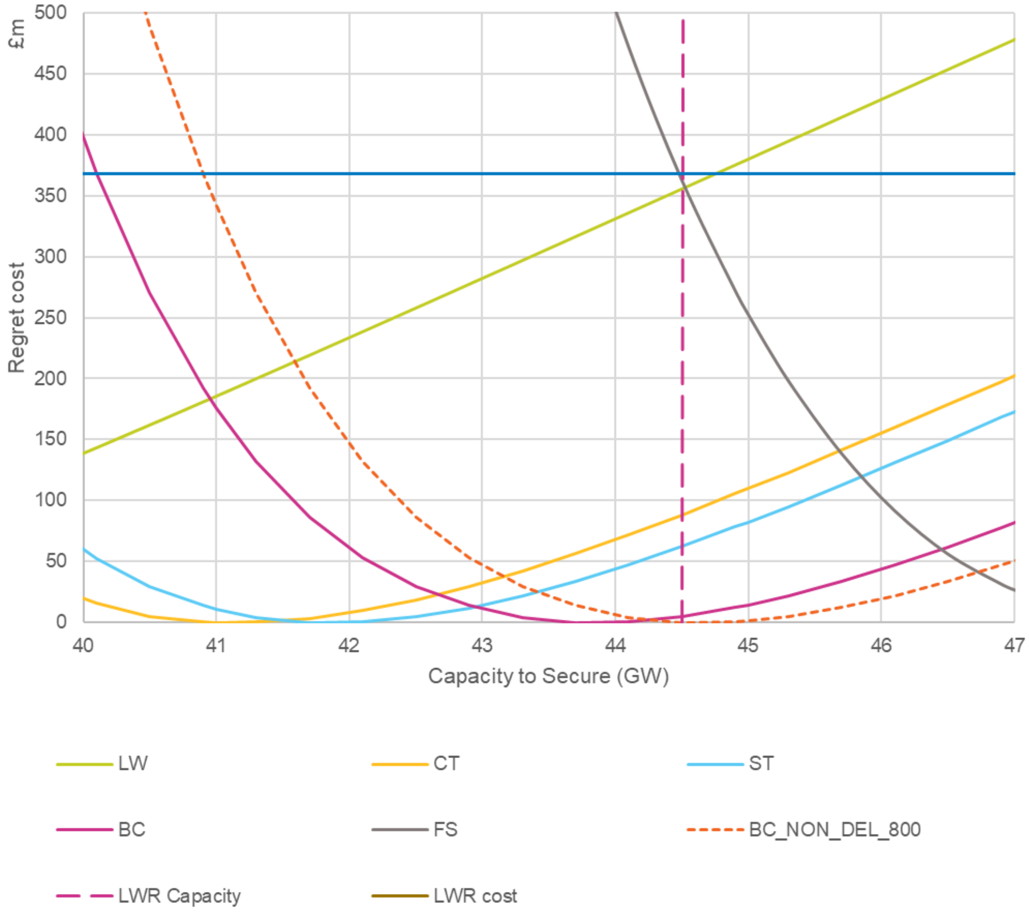
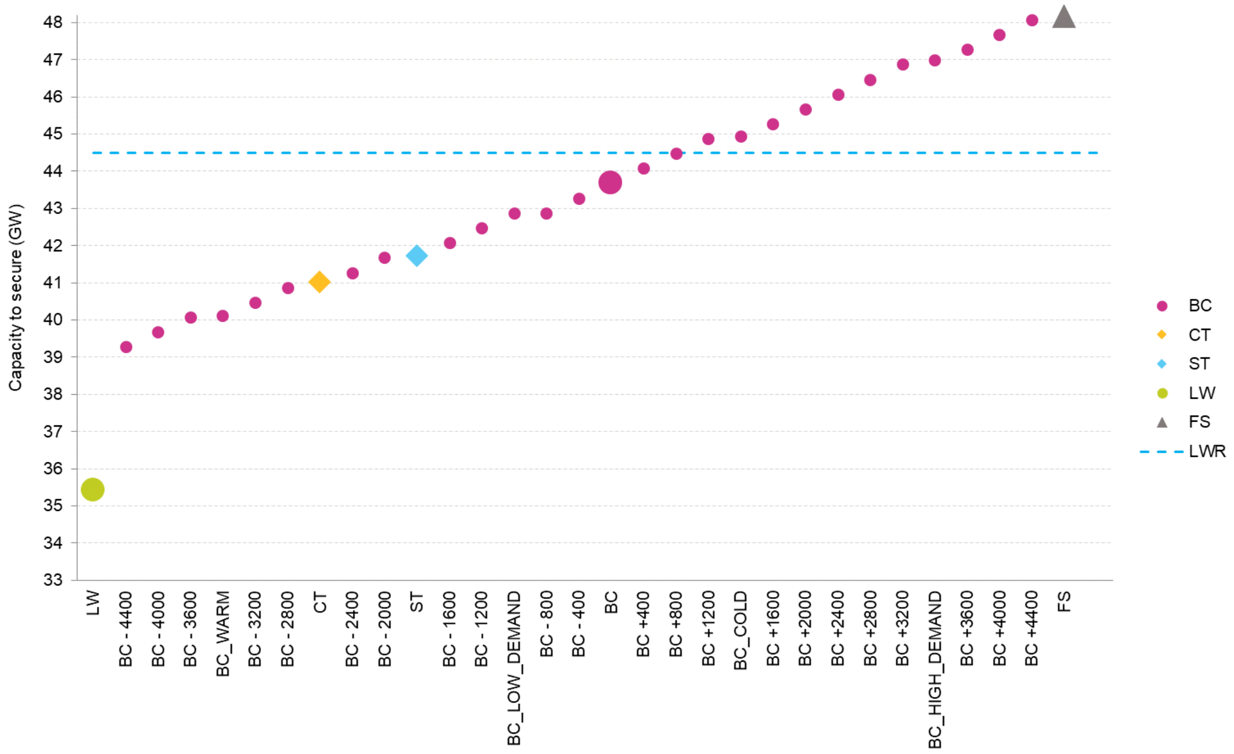


Figure 39 illustrates the full range of potential capacity requirements and identifies the LWR outcome (44.5 GW). The Falling Short scenario has a higher requirement than the other scenarios, mainly due to a higher peak demand and the Leading the Way scenario a lower requirement due to a lower peak demand and higher level of CM-ineligible capacity.

Figure 39: LWR outcome and other cases modelled comparison – 2027/28



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.

If we had used the same approach as in the 2022 ECR (and other previous ECRs), with no modelled unknown non-delivery in the scenarios and sensitivities, but with a range of non-delivery sensitivities up to 7.2 GW (see Table 5 “Total” row), then the target capacity for delivery in 2024/25 would have been the same (44.5 GW).

7.3.1 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 2027/28 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 19 of the 31 cases as shown in Figure 39.

7.3.2 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. This value will be 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 ***w***, ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Government (upon confirming auction parameters to the ESO prior to auction guidelines) will determine how much capacity to hold back for the T-1 auction for 2027/28 – ***w*** GW.
- Government (either upon confirming auction parameters to the 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 the 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 the ESO prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – ***z*** GW.*

Therefore, the recommended capacity to secure through the T-4 auction for delivery in 2027/28 could be:

- 44.5 GW - ***w*** - ***x*** - ***y*** - ***z***.

* The 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 a 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 44.5 GW could result in a differing capacity volume depending on the clearing price set by the marginal unit. The tolerances are set by DESNZ 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.

7.3.3 Comparison with T-4 for 2026/27 recommendation

In the 2022 ECR, we recommended a capacity to secure for 2026/27 of 43.9 GW which was 3.2 GW above the Base Case requirement of 40.7 GW. This recommendation assumed 8.7 GW of previously contracted capacity (net of 0.9 GW storage de-rating change and 0.1 GW assumed non-delivery).

Our recommendation for the T-4 auction for delivery in 2027/28 is 44.5 GW, 0.6 GW higher than our recommendation for 2026/27 in the 2022 ECR. In the 2023 ECR, the recommended capacity to secure corresponds to a LOLE for the Base Case with 6% average future unknown non-delivery of 2.0 hours or 0.3 hours for a Base Case assuming no future unknown non-delivery. This is similar to the 2022 ECR, where the recommended capacity to secure corresponded with a LOLE for the Base Case (assuming 0.1 GW of future non-delivery) of 0.3 hours.

This change is a result of several increases totalling 7.9 GW that are offset by decreases totalling 7.3 GW.

The increases total 7.9 GW:

- An increase of 0.8 GW resulting from the LWR outcome (set by the 0.8 GW non-delivery sensitivity) that is higher than the Base Case requirement
- A 2.3 GW increase resulting from lower non-CM renewable capacity and assumed opted-out or ineligible (below 1 MW) autogeneration (see Table 23 for breakdown) largely due to lower biomass capacity as a result of the end of RO/CFD support for biomass conversions.
- A 0.4 GW increase due to a higher peak demand for 2027/28 compared to the 2022 Base Case peak demand for 2026/27, reflecting a general increase in electrification across each of the sectors with the Future Energy Scenario modelling.
- A 0.4 GW increase in reserve for largest loss for 2027/28 compared to the 2022 Base Case for 2026/27 in line with the updated method implemented as part of the development project addressing PTE recommendation 68 (see Section 3.4.2)
- A 3.1 GW change in the Base Case capacity requirement due to modelled unknown non-delivery (3.2 GW increase in 2027/28 minus 0.1 GW increase in 2026/27). Of the 3.4 GW modelled non-delivery in 2027/28 (see Table 20), around 3.2 GW relates to an increase in capacity requirement to meet 3 hours LOLE and the rest to an increase in wind EFC (included in the other changes below).
- A 0.9 GW increase due to other changes including a change in de-rated margin required for 3 hours LOLE assuming no non-delivery compared to the 2022 Base Case

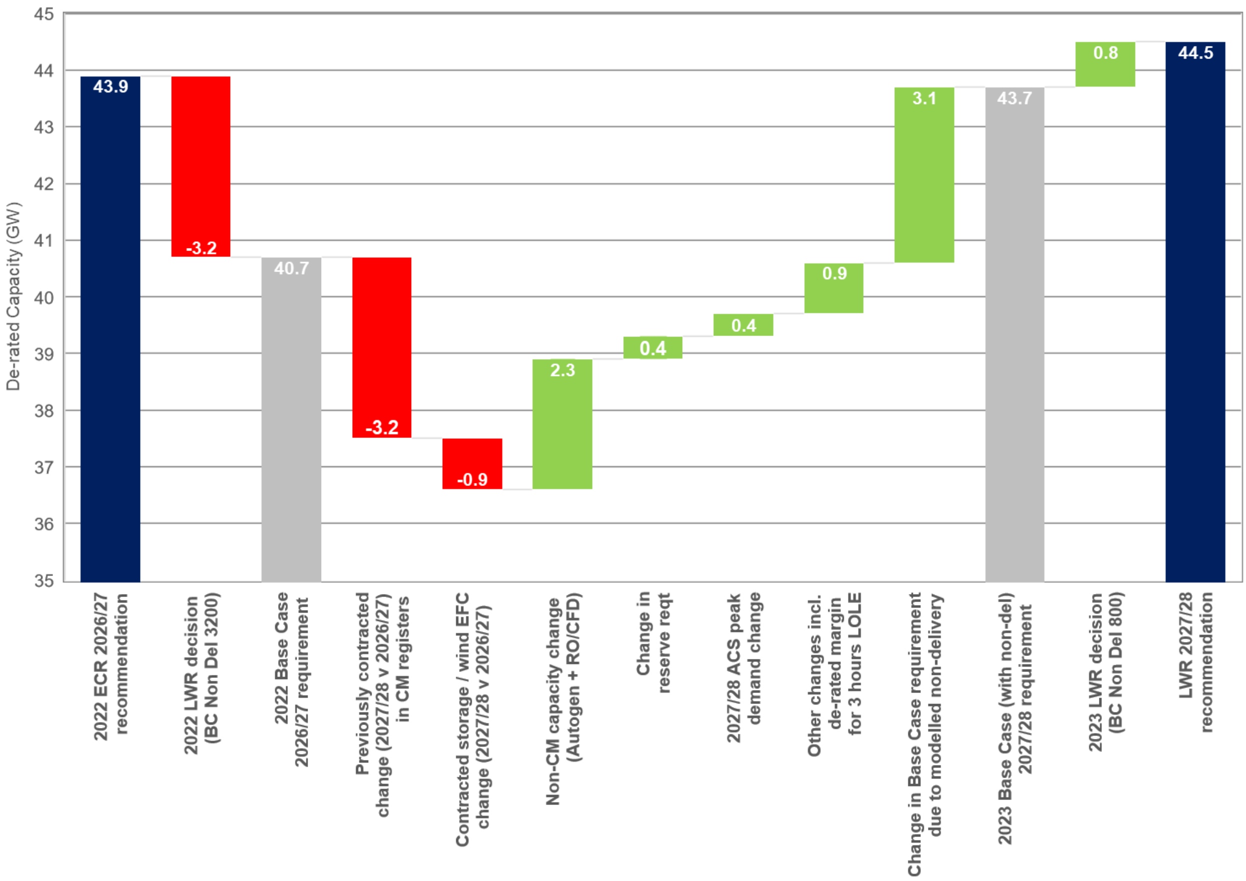
The decreases total 7.3 GW:

- A 3.2 GW reduction from deducting the differential of the 2022 ECR LWR outcome (set by the 3.2 GW non-delivery sensitivity) compared to the 2022 ECR Base Case requirement
- A 3.2 GW net reduction due to an increase in previously contracted capacity arising largely from capacity awarded multi-year agreements in the T-4 auction for delivery in 2026/27.
- A decrease of 0.9 GW due to a change in the EFC of contracted storage and wind compared to the 2022 ECR Base Case (see Sections 7.2 and 7.3.3)

This analysis includes the risk of further non-delivery (up to a maximum of 4.4 GW) in addition to the modelled average 6% non-delivery 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 2026 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.

Figure 40 shows how the original 43.9 GW requirement for the T-4 auction for delivery in 2026/27 (derived from the 2022 Base Case 3.2 GW non-delivery sensitivity) has changed into a recommended requirement of 44.5 GW (derived from the 2023 Base Case 0.8 GW non-delivery sensitivity) as a result of the 0.6 GW net increase described above.

Figure 40: Comparison with recommended T-4 requirement for 2026/27 in 2022 ECR



Note: intermediate totals in grey above show requirements for 2022 Base Case and 2023 Base Case (with non-delivery)

Section 4.9 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 some scenarios, there is a decline in the last few years resulting from an increase in low carbon capacity assumed to be outside of the CM. 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.

7.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery and over-delivery sensitivities, a question was raised around how sensitive the LWR outcome was to the sensitivities included; 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 or added to illustrate how sensitive the outcome is to small changes in the LWR range. 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 21.

Table 21: Sensitivity of LWR outcome to scenarios / sensitivities included in LWR

Sensitivities added or removed	2027/28 outcome
Standard range	44.5
Include additional sensitivity 4.8 GW below the Base Case	44.5
Remove Leading the Way scenario	45.3
Remove Falling Short scenario (and non-delivery sensitivities above high demand[90])	43.7
Include additional sensitivity 4.8 GW above the Base Case	44.9

Removing the lowest target capacity case (Leading the Way) increases the LWR outcome by 0.8 GW. Adding a higher target capacity case (4.8 GW above the Base Case) increases the LWR outcome by 0.4 GW. Removing the highest case currently in the LWR range (Falling Short) as well as the non-delivery sensitivities above the high demand sensitivity reduces the outcome to 43.7 GW. No other single cases affect the LWR outcome. For example, adding additional sensitivities below the lowest sensitivity has no impact on the LWR outcome as the requirement of the LW scenario is well below the requirements of these additional over-delivery cases.

We consider the outcome of the LWR calculation to be suitably robust and that the choice of scenarios and sensitivities included are well-justified as set out in Chapter 4.

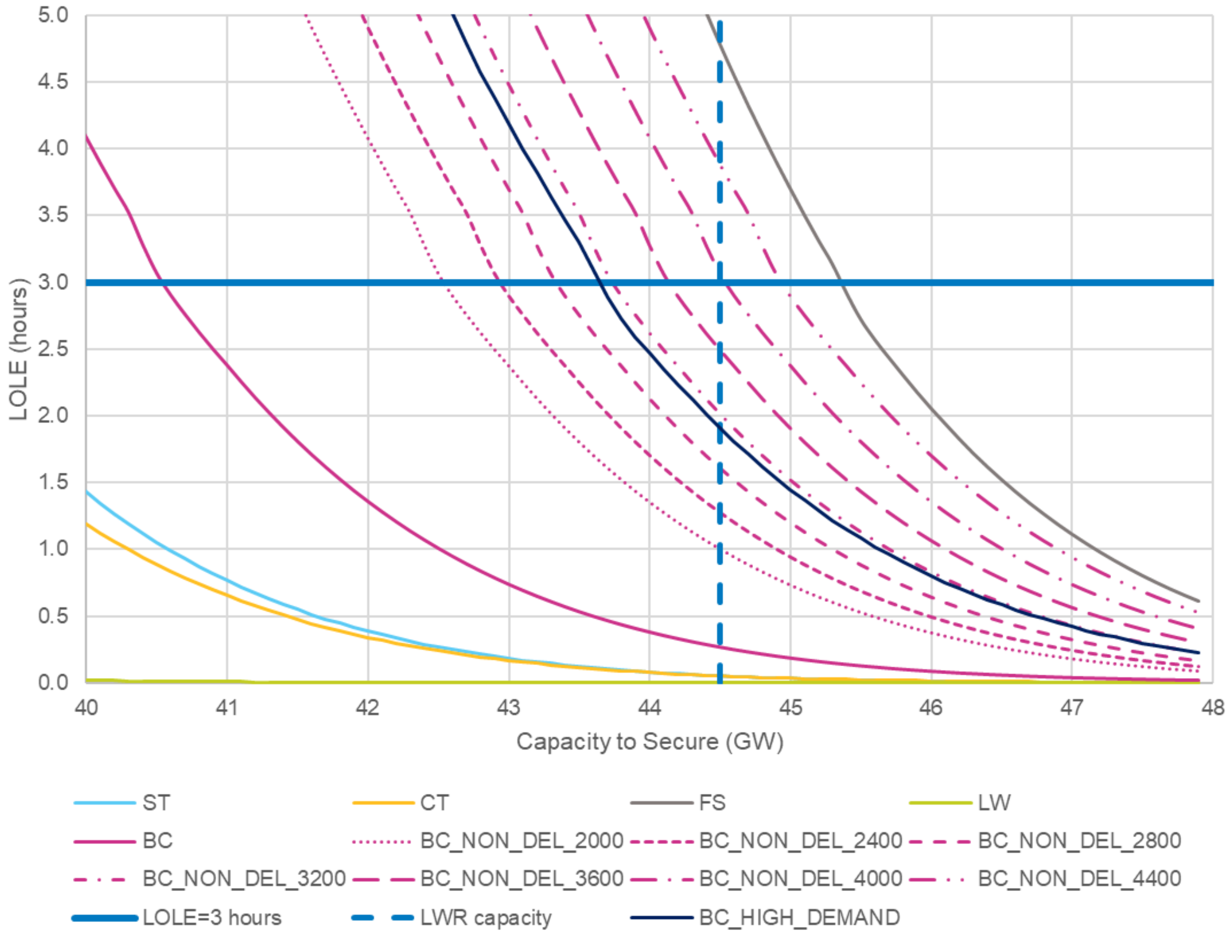
7.3.5 Sensitivity of LOLE to T-4 Capacity to Secure

In the 2023 ECR, the recommended capacity to secure corresponds to a LOLE for the Base Case with 6% average future unknown non-delivery of 2.0 hours or 0.3 hours for a Base Case assuming no future unknown non-delivery. To help decision makers to understand the sensitivity of LOLE to the target capacity chosen for the T-4 auction, we have included Figure 41 which illustrates how the LOLE for the scenarios and highest sensitivities varies with capacity to secure. We have not included all of the sensitivities on the chart to avoid overcrowding but the other sensitivities have LOLE values below the sensitivities shown (the values for all scenarios and sensitivities are in the ECR Data Workbook). The values shown have been adjusted to show the LOLE assuming no modelled non-delivery to enable comparison with the equivalent chart in the 2022 ECR.

As can be seen, reducing the capacity to secure to 42.5 GW would mean that the LOLE for the sensitivities shown would be 3 hours or above and increasing the capacity to secure to 45.4 GW would keep the LOLE to 3 hours or below for the FS scenario (without modelled non-delivery) and all the other sensitivities shown. The LOLE for the Base Case (without modelled non-delivery) is 0.3 hours for the recommended capacity to secure (44.5 GW) – this would increase to 1.0 hours for a capacity to secure of 42.5 GW and reduce to 0.1 hours for a capacity to secure of 45.4 GW.

[90] Assuming that the non-delivery sensitivities are not able to set the upper bound of the range of the LWR calculation (see Section 3.5)

Figure 41: Sensitivity of LOLE to Capacity to Secure assuming no non-delivery – 2027/28



A. Annex

A.1 Demand Methodology

The demand projections are developed using in-house analysis informed by stakeholder feedback. Annual demands can be considered with the following breakdown:

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

A.1.1 Domestic Demand

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[91].
- **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

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

be installed to differing degrees in order to optimise the overall GB energy system, particularly peak demands during winter

- **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.

A.1.2 Industrial Demand

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.

A.1.3 Commercial Demand

The same approach as described in the paragraphs above (in the industrial section) has been adopted this year. We include granular projections for growth of some important subsectors such as data centre demand.

Our spatial heat model outputs results for commercial heat with granularity on a regional level[92]. The 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.

A.1.4 Transport Demand

- **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.

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[92] https://www.nationalgrideso.com/document/190471/download

- **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.

A.1.5 Peak Demands

Once the assessment of underlying annual demand is created, a recent historical relationship of annual to peak demand is applied. This creates an underlying peak demand to which peak demand components that history cannot predict 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)[93] 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.

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

A.1.6 Calibration

Both annual and peak demands are calibrated. Annual demands are calibrated to weather corrected metered transmission data, DESNZ information and the FES assessment of non-transmission generation. The peak demand considered for the Base Case is the Average Cold Spell (ACS) demand.

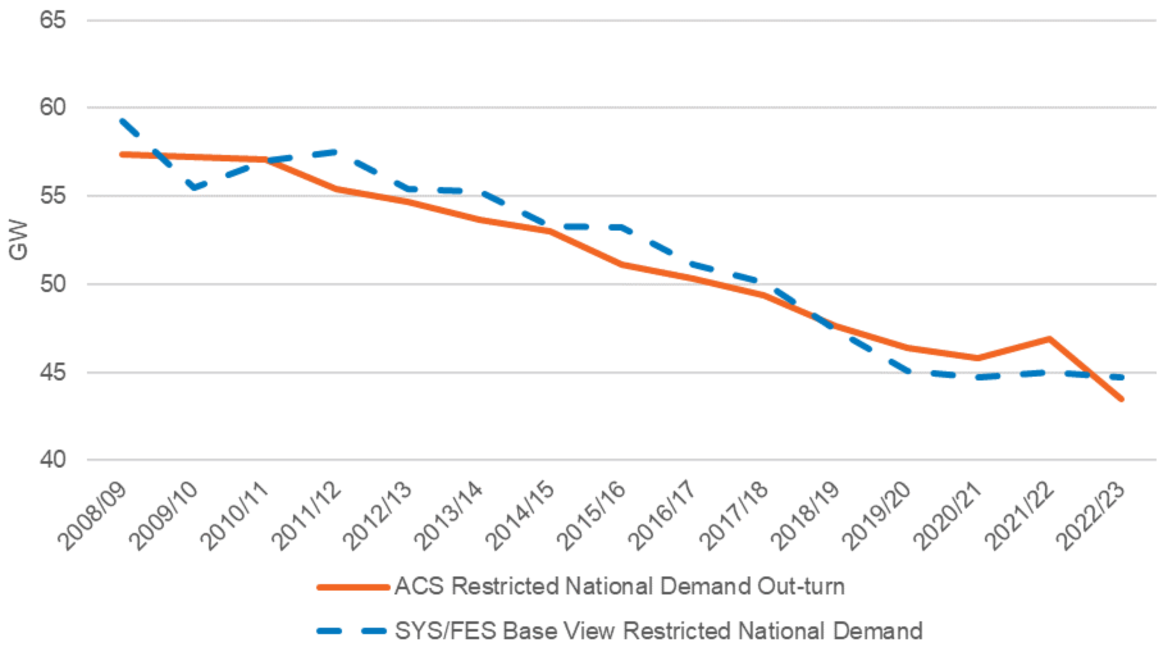
A.1.7 Results

The results of the described methods provided are defined and shown in the Annex (Section A.5.1). For a more detailed description of the methodology and FES scenarios please refer to the FES Report, the FES Modelling Methods document or the FES Data workbook[94]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

A.1.8 Recent forecasting performance

The PTE included data on the ESO's demand forecasting performance in their 2019 report. Figure 42 provides an updated view of this data showing a comparison of the ESO's winter ahead ACS restricted national demand forecast against outturn values. Only the 2022/23 year has been updated for the 2023 ECR.

Figure 42: ACS Restricted National Demand Forecasting Accuracy



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

A.2 Generation Methodology

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

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

The placement of a power station was determined by a number of factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that particular power station, are also taken into account. The contracted background or Transmission Entry Capacity (TEC) Register[95] 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 Embedded Capacity Register.

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:

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

1. Is the developer a portfolio player who may have a number of potential projects at different stages of the process, in which case intelligence is gathered on the developers ‘preferred’ or ‘priority’ projects, or is it a merchant developer who is looking to become active within the electricity market?
2. How active is the developer in the GB electricity market?

Technology

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

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

Financial Markets

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

Consideration is also given to the economics for different types of generation, in terms of electricity wholesale prices, fuel prices and the impact of the carbon price (i.e. clean dark and spark spreads) which may impact the operational regime on a technology and/or plant-specific basis. The FES Data Workbook contains details of these price assumptions[96].

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

[96] E.g. for FES 2022 see tabs CP1 (fuel prices) and CP2 (carbon prices) of: https://www.nationalgrideso.com/document/263876/download

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[97].

A.3 ESO Analysis Delivery Timeline 2023

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

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

The work was carried out between September 2022 and May 2023 and builds on the analysis that was undertaken for the previous ECRs. 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 2022
- Development projects phase October 2022 to February 2023
- Production plan developed in February 2023
- ECR modelling March to May 2023
- ESO's ECR sent to DESNZ before 1 June 2023
- Publication of ECR in line with DESNZ publishing auction parameters in July 2023

A.4 EMR/Capacity Assessment Development Projects Matrix

Table 22 lists all the proposed development projects and their respective ranking scores. Projects without a score were in progress or completed prior to the ranking exercise. Note that shaded projects either did not rank high enough or were deprioritised and therefore were not progressed.

Table 22: Development Projects Matrix

Ref.	Development Project Description	Rank*
PTE60 phase 2	Develop and implement new functionality in the DDM to model uncertainty over future non-delivery probabilistically	1
PTE71	To consider the use of operational data for estimating battery derating factors instead of, or in combination with, the model-based EFC approach used at present	1
PTE72	To expand the statistical analysis of ICDRFs to fully understand the implication of bimodal distributions for individual flows and their correlations on the aggregate and individual risks of GB interconnections	1
EMR100	Review of the process by which modelled ranges for interconnected countries are used to inform a single auction de-rating factor	1
EMR104	To investigate why the embedded wind output from the capacity assessment model is much higher than the values published on the ESO data portal	5
EMR105	To review and revise the GB interconnection probability distribution used in the DDM to calculate the interconnection EFC	5
EMR107	To review the de-rating factor to be used for biomass conversion units	5
EMR108	To review the ongoing impact of Russia's illegal invasion of Ukraine to see there is any impact on the capacity to secure targets for the 2023/24 T-1 and 2026/27 T-4 auction targets as part of the annual autumn adjustment process following prequalification. We may also be asked to carry out ad-hoc analysis (not directly related to auction targets) due to Ukraine and the cost of living crises. This time needs to be allowed for in the development plan	5
PTE66	To accelerate the work on the statistical representation of peak demand uncertainty around the Base Case for the T-1 and T-4 years with a clear identification of what uncertainties can be modelled statistically and what are being left to expert judgement.	5

Ref.	Development Project Description	Rank*
PTE67	Analysis of the price elasticity of demand by market segments in order to better understand the underlying demand under current high prices and potentially project future high price sensitivity more accurately.	5
PTE68	To consider if the capacity of facilities providing ancillary services is being accounted for properly in the resource adequacy calculation under stress events.	11
EMR110	To develop the interconnector modelling functionality in our new European model (Plexos) to ensure that Plexos can carry out the modelling tasks currently carried out in BID3 as well as potential modelling improvements	11
PTE53 Phase 3	Further consideration of whether de-rating factors for embedded generation could be derived from alternative data sources	13
EMR101	Conventional plant de-rating factors are based on availability at times of high demand. This project would assess availability of conventional generation at times of high demand-net-of-wind	13
PTE64	The consistency of the implicit derating of interconnectors for the DDM procurement analysis and the determination of individual country derating factors should be made more transparent	13
PTE69	To investigate if network infrastructure constraints present a material degradation of the achievement of the reliability standard for capacity adequacy.	13
PTE73	The modelling parameters in the ECR related to the reliability standard are not well matched to the preferences and policies of procurement. It would improve the relevance of the ECR exercise if BEIS were to reinstate its intention to review the reliability standard and its implementation.	17
EMR86	Explore the potential for capturing more of the modelling uncertainties in the DDM and investigate what it may take to get a fully stochastic model	17
EMR103	Automate and streamline data processing of the Capacity Assessment model and automate the data required for Winter Outlook analysis / charts.	17
PTE62	BEIS and Ofgem should consider the timing of all CM related activities each year in order to allow pre-qualification and auction results to better inform National Grid ESO's modelling and give parties longer to deliver new build plant after the T-4 auction	20
EMR80	Review of assumptions and method that leads to the construction of the conventional distribution used in the LOLE calculation.	20
EMR67	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	20
EMR82	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.	23
EMR60	To review 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.	23
EMR97	Assess emerging risks to security of supply	23
EMR102	To review and investigate the levels of granularity of wind turbine data (co-ordinates, hub data) required for CA model. For example, use one single set of co-ordinates for the whole area (FLOP zone, county) and compare this to current method of having co-ordinates for each wind farm. Investigate also how to simplify the hub height.	26

Ref.	Development Project Description	Rank*
EMR106	To review and potentially update the functionality in the UEM to account for greater uncertainties	26
PTE63 Phase 2	A more thorough analysis of the duration limits for turn-down DSR should be undertaken	26
EMR109	To carry out an in-depth review of the content and potential format of the ECR document(s) in consultation with BEIS / PTE	27
EMR59	Improve historical demand time series for LOLE modelling (using Electralink data)	28
EMR68	Develop methodologies for calculating de-rating factors for new technologies that may enter the CM auctions	28
EMR94	Creation of queries to extract data from a new FES database to be set up (on a new Data Analytics Platform) - may be deferred to later as Data Analytics Platform is not yet built	28
PTE70	To consider the use of operational data for estimating wind derating factors instead of, or in combination with, the model-based EFC approach used at present.	31
EMR45	Develop a proper demand time series shape for FES future security of supply modelling - at the moment we are using 2005/06-2020/21 demand time series shapes, but these are likely to be inadequate for > FES 2030 margins assessment work.	31
EMR61	If the introduction of a large offshore wind power curve is justified (see EMR60), update models (CA model, DDM, UEM) to incorporate this new class. Calculate the impact on de-rating factors, LOLE, capacity to secure etc.	31
EMR81	Investigate the feasibility of whether we can use PLEXOS for capacity assessment modelling that could allow us to retire our internal capacity assessment model used for Winter Outlook	31
EMR84 Phase 2	Work with the Met Office to obtain data at hourly resolution - if this happens we will look to explore the use of this data in our modelling	35
EM103	Automate and streamline input data processing of the CA model and automate the data required for Winter Outlook analysis / charts.	Not scored
EMR93 Phase 2	To further streamline and automate the 'FES to DDM' translation tools (Python/Excel/csv)	Not scored

*represents total scores based on scorings provided by ESO, DESNZ and Ofgem.

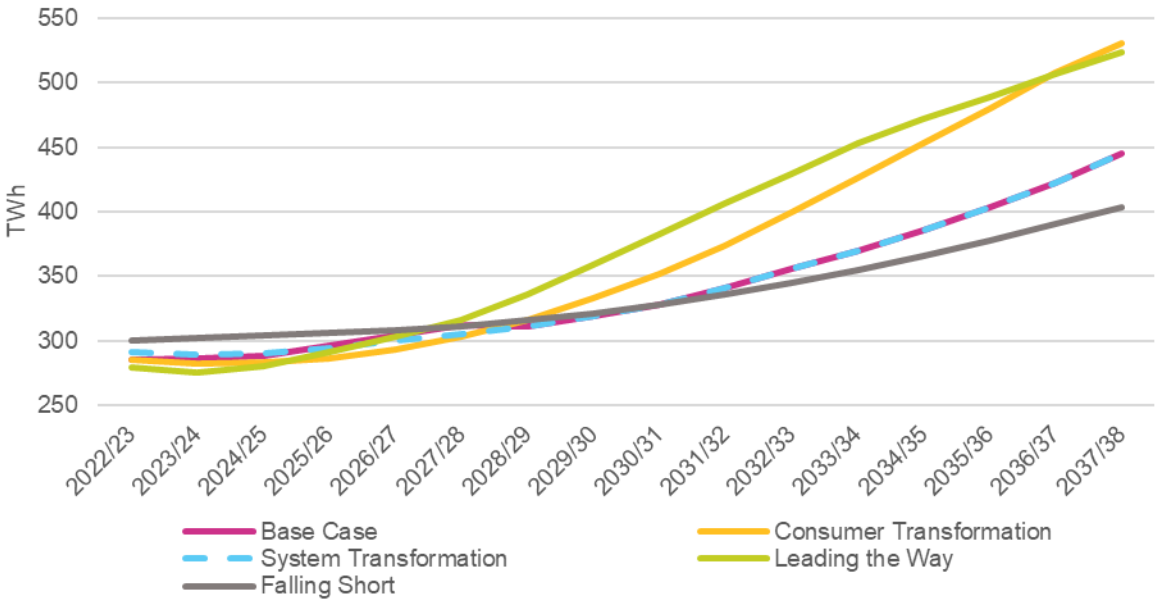
A.5 Detailed Modelling Assumptions

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

A.5.1 Demand (annual and peak)

Figure 43 shows the annual demand used for Base Case and the four 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).

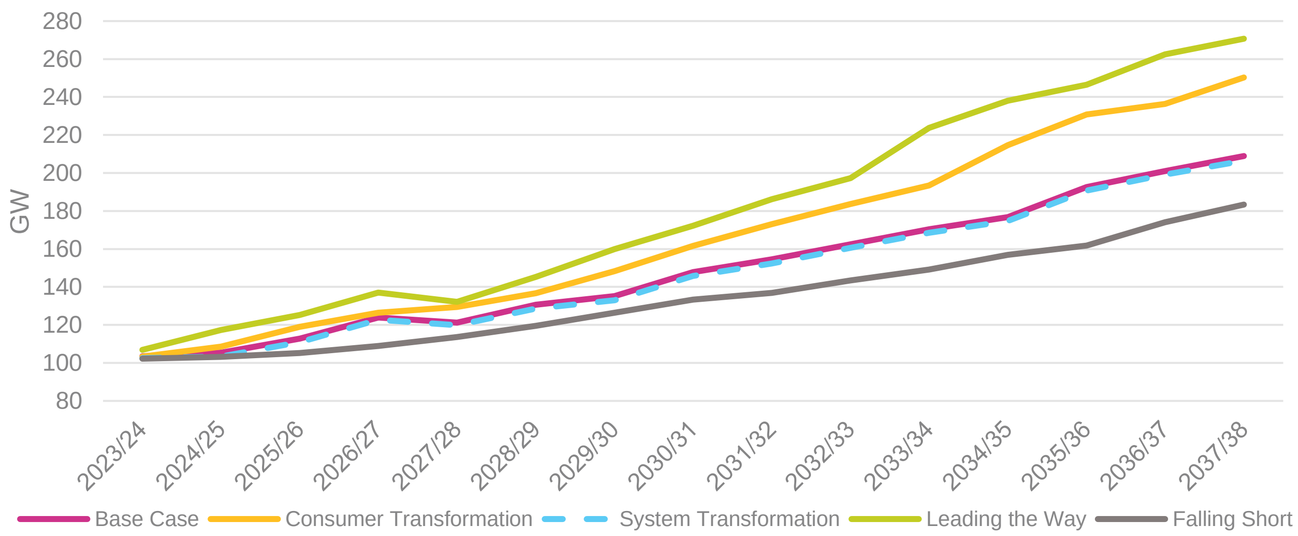
Figure 43: Annual demand by scenario



A.5.2 Generation Capacity Mix

Figure 44 shows the generation mix (nameplate capacity at winter peak, excluding solar PV) for the four FES scenarios and Base Case from the DDM model. The ECR Data Workbook shows the split between CM and non-CM capacity. The Non-CM capacity shows increases in most years after 2023/24 but falls in 2027/28 more most scenarios due to the end of RO and CFD support for biomass conversion.

Figure 44: Generation peak capacity by scenario



A.5.3 CM-ineligible Capacity

Table 23 gives a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2024/25 and 2027/28. The autogeneration in 2024/25 includes 0.4 GW assumed over-delivery (see Section 5.2). Please note that the capacities by technology may not sum to the total ineligible capacity due to rounding.

Table 23: Breakdown of De-rated CM ineligible capacity (GW) for 2024/25 and 2027/28

Generation type	2024/25 Capacity (GW)	2027/28 Capacity (GW)
Onshore Wind	2.7	3.2
Offshore Wind	3.0	3.9
Biomass	3.9	1.4
Autogeneration	0.6	0.2
Hydro	0.9	1.0
Landfill	0.4	0.4
Other	1.3	1.8
Total	12.8	11.8

A.5.4 Station Availabilities

Small-scale/embedded CM-eligible technologies are mapped to the closest equivalent transmission-connected technology class, as required by the CM rules. For some 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, with results summarised in Figure 45. Interconnection EFC values are calculated using the method described in Section 3.3.2 of this report. The EFCs for storage, wind and solar for the DDM runs are different to the auction de-rating factors described in Section 5.1 as per Section 2.5.2 of the 2019 ECR[98]:

- Storage de-rating values in the DDM are set so that the total DDM storage de-rated capacity (GW) matches the Unserved Energy Model (UEM) storage fleet EFC (GW). This approach gives T-1 year values for durations 6 hours and above that match the pumped storage availability of 94.37%, with durations below provided the average of the remaining storage fleet EFC (20.86%). For the T-4 year, all durations receive the fleet average EFC of 30.51%.
- Wind EFC %s (shown in Figure 46) are calculated by the DDM using a scaling factor of 0.75 that reduces wind generation on high demand days. This value was set in 2019 so that the DDM wind EFC broadly matched the UEM wind fleet EFC (GW).
- Solar EFC %s (shown in Figure 46) are calculated so that the sum of the individual fleet EFCs (wind EFC + storage EFC + solar EFC) in the UEM broadly matched the combined unconventional (wind+storage+solar) fleet EFC.

[98] See page 23 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

Figure 45: Non-CM technology availabilities

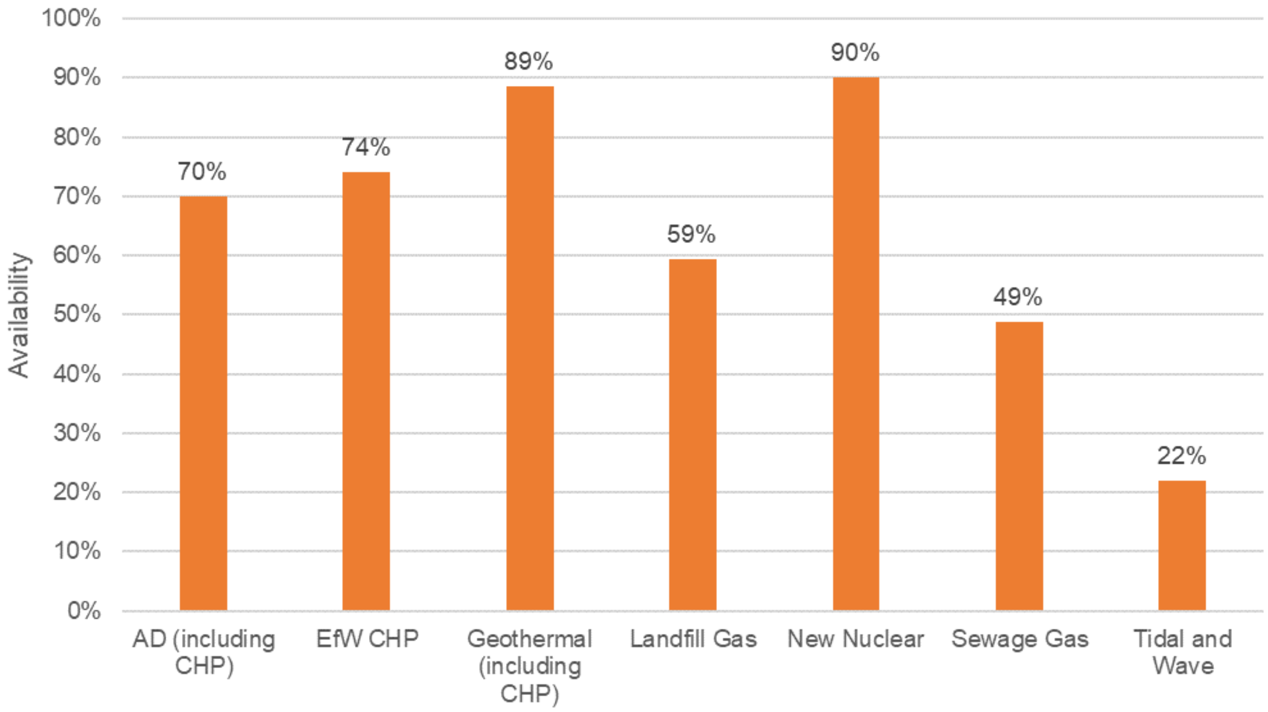
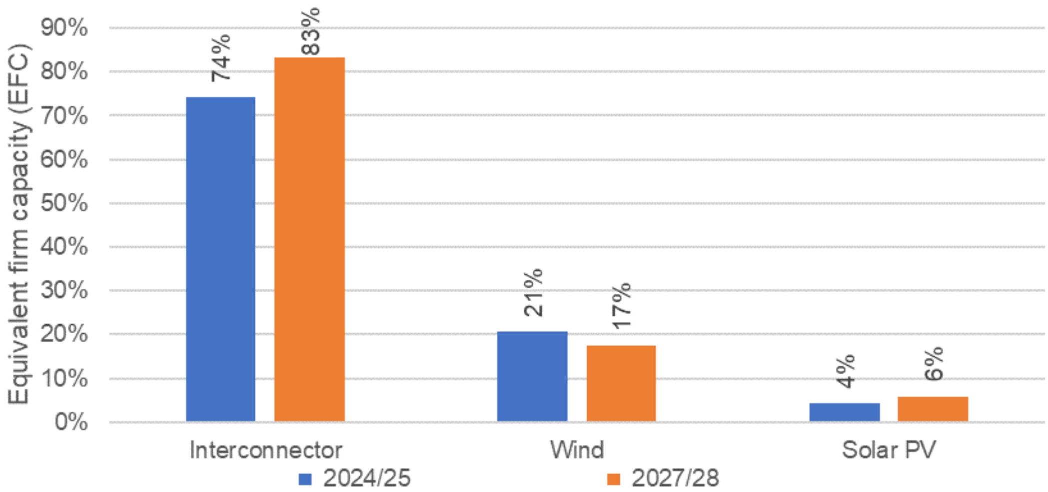


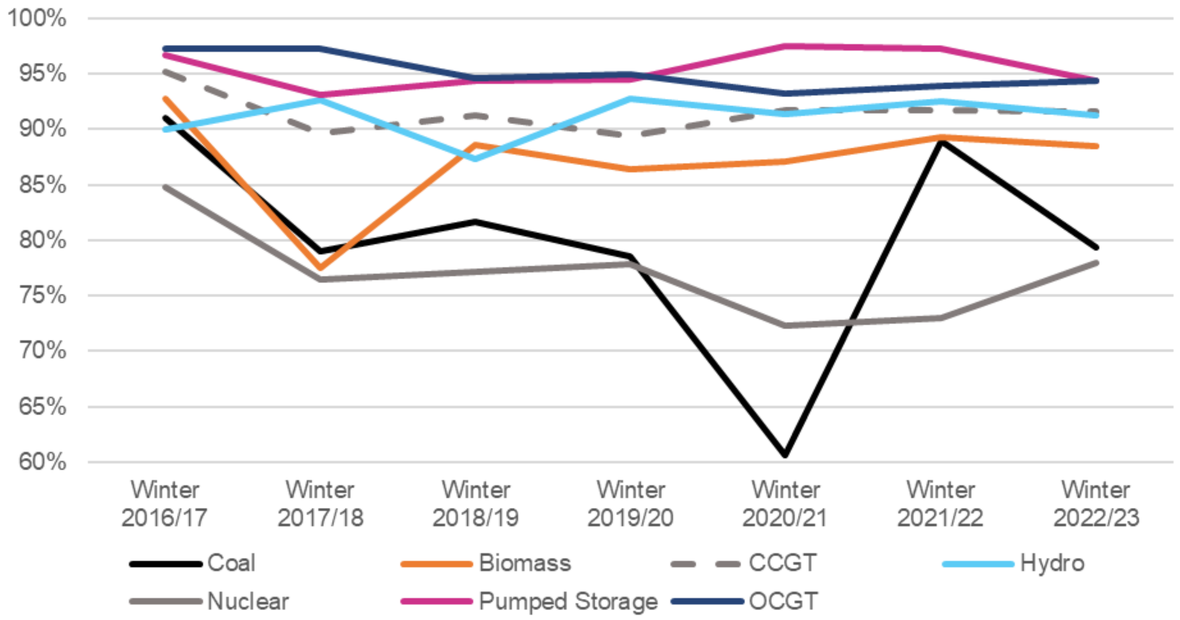
Figure 46: Interconnector, wind and solar fleet EFCs



A.5.5 Conventional Transmission Station Availabilities

Figure 47 shows the station availabilities from each of the previous 7 winters for transmission-based generation.

Figure 47: Station availabilities

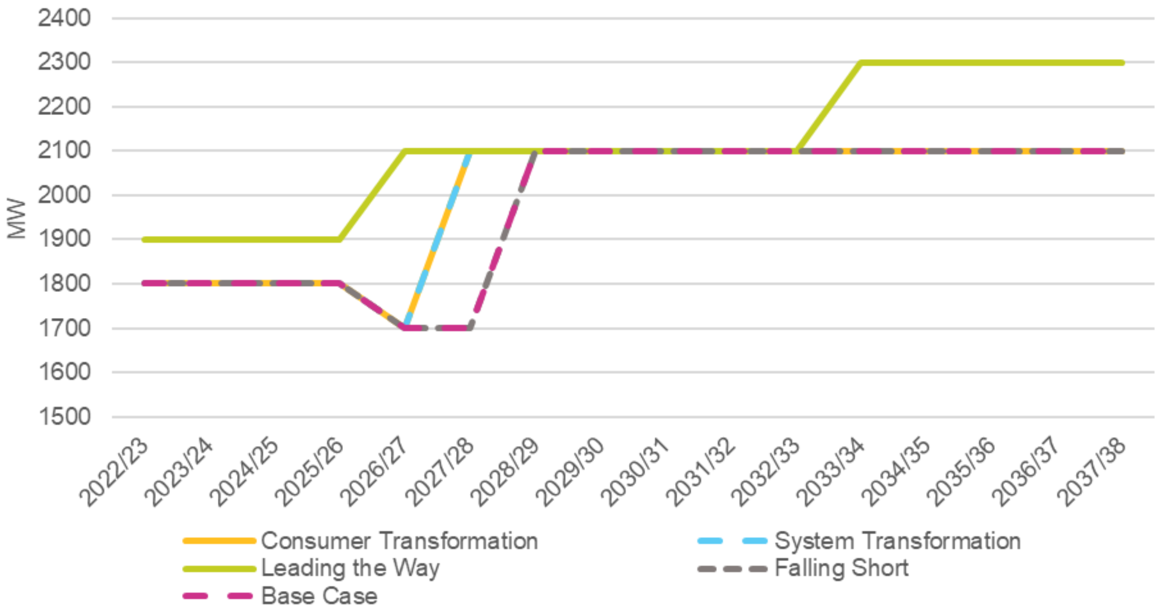


A.5.6 Reserve and response for largest loss

The 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 and response for largest loss requirements depend on a number of factors. This includes the largest loss on the system and the forecast demand. Figure 48 shows the reserve and response requirements to cover the largest in-feed loss[99] 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 and response for largest loss.

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

Figure 48: Reserve and response for largest loss by scenario



A.5.7 Conventional Plant Types

Table 24 describes the plant types included in each technology class.

Table 24: Conventional Plant Technology Classes

Technology Class	Plant Types Included
Oil-fired steam generators	Conventional steam generators using fuel oil
Open Cycle Gas Turbine (OCGT)	Gas turbines running in open cycle fired mode
Reciprocating engines **(non-autogen)**	Reciprocating engines not used for autogeneration
Nuclear	Nuclear plants generating electricity
Hydro (excl. tidal / waves and pumped storage)	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
CCGT	Combined Cycle Gas Turbine plants
CHP and autogen	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas
Coal	Conventional steam generators using coal
Biomass	Conventional steam generators using biomass
Energy from Waste	Generation of energy from waste, including generation of energy from:

Technology Class	Plant Types Included
	a) conventional steam generators using waste; b) anaerobic digestion; c) pyrolysis; and d) gasification.
DSR[100]	

A.6 Detailed Modelling Approach

A description of the detailed modelling approach was included in page 81 of ECR 2017[101].

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.6.1 Assumptions for the over-delivery and non-delivery sensitivities

Table 5 and Table 7 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 that results in the maximum value for each year. Table 25 and Table 26 provide further commentary on these values.

[100] 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

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

Table 25: Assumptions for non-delivery sensitivities

Non-delivery type	2024/25 T-1	2027/28 T-4	Comments
Large thermal	3.0	3.9	There is significant uncertainty on large thermal assets (coal and gas) due to challenging economic conditions and the drive to net zero. The higher T-4 number reflects greater uncertainty and risk on this time horizon.
Nuclear	1.8	0.0	We have experienced recent winters with two stations on extended outages (2018/19 to 2020/21). The lower T-4 number reflects expected closures of the nuclear fleet.
Small thermal and storage	0.7	1.8	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 could also cover some risk of delays to new projects. The higher T-4 number reflects greater uncertainty and risk on this time horizon.
Unproven DSR	0.3	0.3	Reflects risks from previous observations that up to around 25% unproven DSR has failed metering tests in the past
Interconnectors	3.0	3.3	Non-delivery based on combination of assuming interconnectors deliver in line with lower end of de-rating factor range based on our modelling (represents 2.3 GW for T-1 from 2020 ECR for 2024/25 and 2.6 GW for T-4 from 2022 ECR using 2026/27) and interconnector reliability (assumed 0.7 GW based on a single cable outage).
Sum of non-delivery	8.8	9.3	
Market response	-1.7	-2.1	Potentially 1 GW from thermal plant staying open so this effectively offsets some of the non-delivery for large thermal. Potentially some response from interconnectors assuming 1/3 of the difference between auction de-rating factors and the top end of our previous modelled ranges.
TOTAL	7.1	7.2	Net total of around 7.2 GW is broadly consistent with the highest levels of past non-delivery observed in PTE 61 post T-1 auction.
Base Case Adjustment	[4.0] rounded	[4.4] rounded	We model an average non-delivery probability (approximately 3.0GW)

* All values rounded to nearest 0.1.

Table 26: Assumptions for over-delivery sensitivities

Over-delivery type	2024/25 T-1	2027/28 T-4	Comments
Large thermal	1.0	1.0	Based on estimates that a large thermal plant many stay open without a CM agreement.
Nuclear	0	0	We assume nuclear stations will have a CM agreement if they are available.
Small embedded	1.5	1.5	Estimate based on comparing assumptions in our 2020 Base Case with capacity contracted in the CM for delivery years 2017/18 to 2020/21. Potentially as much as 1.5 GW staying open but not contracted, although highly uncertain. It could also include early delivery of new build projects.
Unproven DSR	0.3	0.3	Based on estimates of DSR without agreements from 2018/19
Interconnectors	2	3.1	Assumes over-delivery in line with high end of de-rating factor ranges with 5% reduction to reflect technical reliability (represents 2.0 GW for T-1 from 2020 ECR for 2024/25 and 3.1 GW for T-4 from 2022 ECR using 2026/27)
Sum of over-delivery	4.8	5.9	
Market response	-1.73	-1.4	Assume 0.5 GW large thermal (e.g. CCGT) could close early in response to over-delivery from other sources plus lower imports from interconnectors, which may not be needed as much (assumes 1/3 of the differences between auction de-rating factors and lower end of previous modelled range)
TOTAL	3.6 rounded	4.4 rounded	

* All values rounded to nearest 0.1.

A.6.2 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'[102], 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 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 system. Given this, we agreed with DESNZ 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 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. Specifically, we assume that gas markets will continue to function effectively.

Adverse weather events – Our weather history is relatively short (< 17 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 previously supported a project led by the National Infrastructure Commission and Met Office to develop

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

credible adverse weather data sets that can be used by energy modellers. This included development of weather scenarios that could have occurred but haven't. We continue to engage with the Met Office and others to develop these scenarios into formats suitable for our modelling.

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 small portion of the year, which may not be significantly impacted by running hour restrictions.

A.7 Storage De-rating Factor Data Assumptions

As reported in Sections 3.3.3 and 5.1, we have calculated the de-rating factors for duration limited storage in the 2023 ECR based on an updated view of storage durations and capacities (as per Figure 49 and Figure 50 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[103] 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 (for further explanation, see our storage and renewables de-rating factor briefing note[104]):

- 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, 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 short duration storage in the Base Case will tend to reduce the incremental EFC of storage units added thereafter. The assumptions in the 2023 ECR Base Case for the penetration of storage by capacity and duration are listed in the figures below.

- 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 (TA-PS) over the last 7 years' winter periods - calculated as 94.37% this year.

- The histogram of stress event durations of the same Base Case (see Figure 51 and Figure 52), whereby all durations at or above that duration threshold which corresponds to longer than 95% of potential stress events shall receive a de-rating factor equal to the historical technical availability of pumped storage (TA-PS), and those that are shorter than

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

[104] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Storage%20and%20Renewables%20De-rating%20Factors%20Briefing%20Note%202023.pdf

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).

Figure 49: Base Case duration limited storage T-1 assumptions (near final)

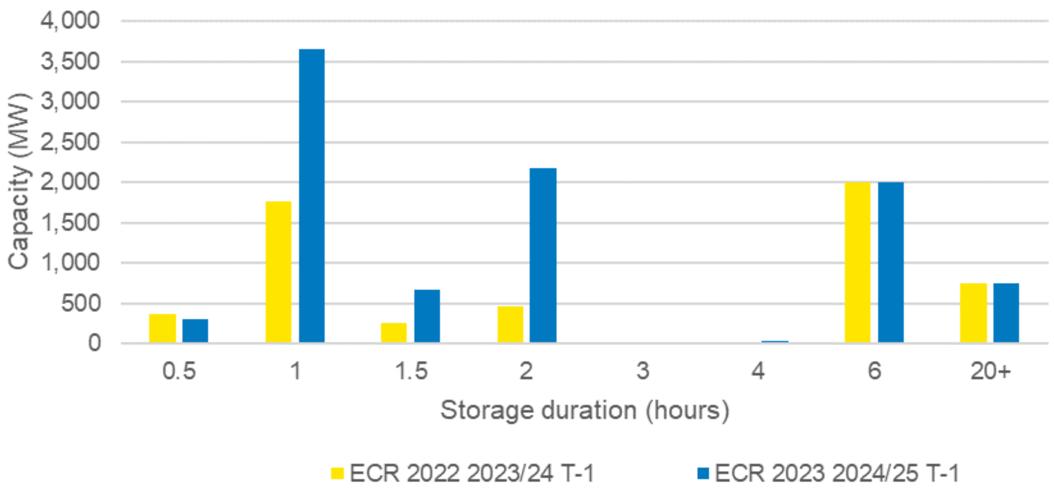
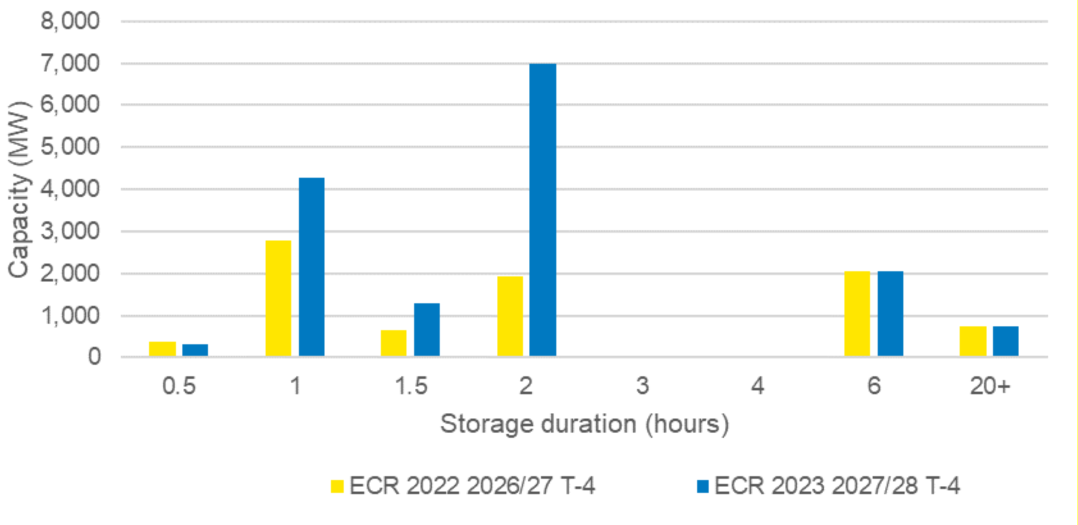


Figure 50: Base Case duration limited storage T-4 assumptions (near final)



For both the T-1 year and the T-4 year, there is a significant overall increase in the amount of shorter duration storage capacity in the 2023 ECR Base Case compared to the 2022 ECR Base Case. In particular, there is an increase in capacity for 1-2 hour duration systems offset slightly by a small decrease in 0.5 hour duration capacity. This change primarily reflects the capacity procured via the T-1 auction for delivery in 2023/24 and the T-4 auction for delivery in 2026/27.

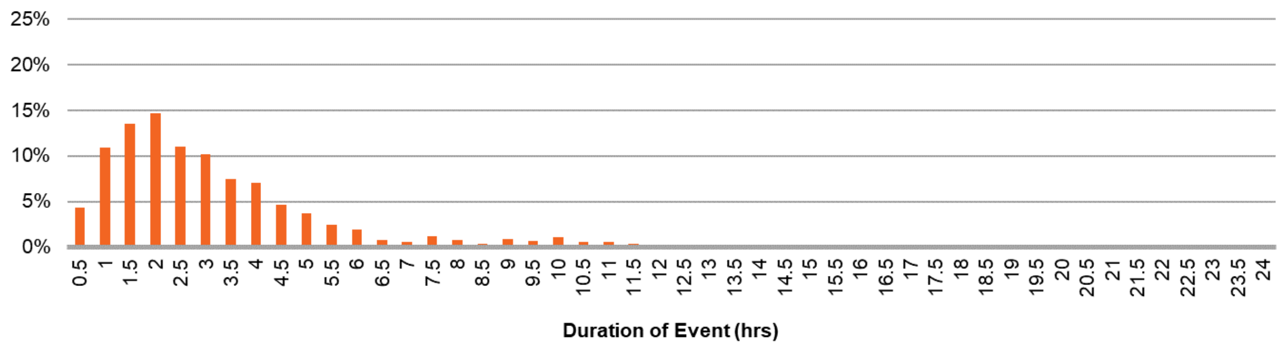
Our renewables de-rating consultation[105] showed (slide 22) that solar capacity also has an impact on storage incremental EFCs, with large increases in solar capacity resulting in modest increases in

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

storage EFCs. However, this impact is small compared to the impact of increases in short-duration storage capacity that reduces the storage incremental EFCs.

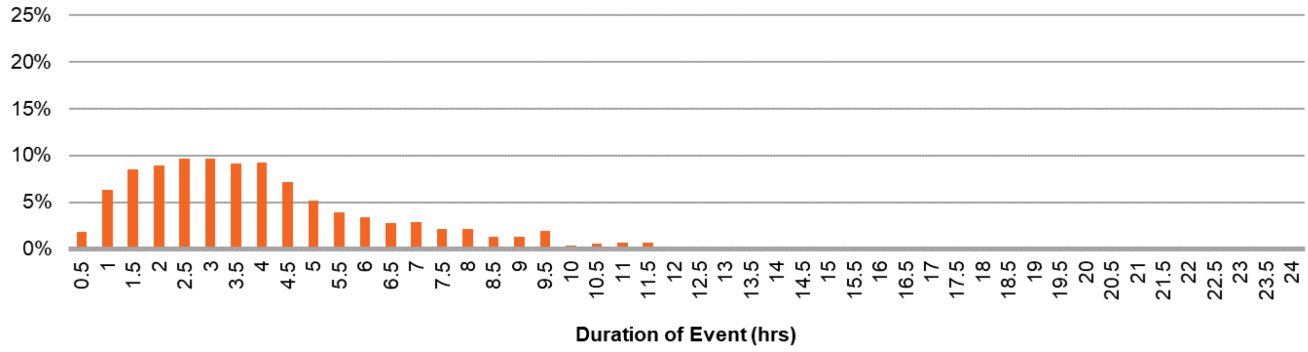
Due to the higher storage capacity, the incremental EFCs have decreased since the 2022 ECR for the T-1 and T-4 years. In addition, the duration threshold corresponding to 95% of stress events has increased from 6 hours to 8 hours in the T-1 year. The duration threshold corresponding to 95% of stress events has decreased slightly from 9.5 hours to 9.0 hours in the T-4 year due to an increase in events with durations between 4 and 9 hours, which slightly exceeds the decrease in events with durations between 0.5-2.5 hours. These changes have resulted in lower de-rating factors for durations below these new duration thresholds in the T-1 and T-4 years. 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[106] in the T-1 and T-4 years is illustrated in Figure 51 and Figure 52.

Figure 51: Stress Event Duration Histogram for 2024/25 T-1 Base Case at 3 hours LOLE



Note: the mean event duration in 2024/25 is 3.1 hours

Figure 52: Stress Event Duration Histogram for 2027/28 T-4 Base Case at 3 hours LOLE



Note: the mean event duration in 2027/28 is 4.0 hours

[106] 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

A.8 Least Worst Regret

Details of Least Worst Regret approach and methodology can be found in page 87 of the 2017 ECR[107].

A.9 ECR Recommendations and CM Auction Summary

The ECR Data Workbook summaries the ECR recommendations, recommended demand curve target adjustments after prequalification, Secretary of State (SoS)'s decisions, capacity secured [108] (all in MW) and clearing prices (in £/kW) by auction.

A.10 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 DESNZ's Modelling Integrity team to ensure that the QA process closely aligned to DESNZ's in-house QA process[109]. 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.

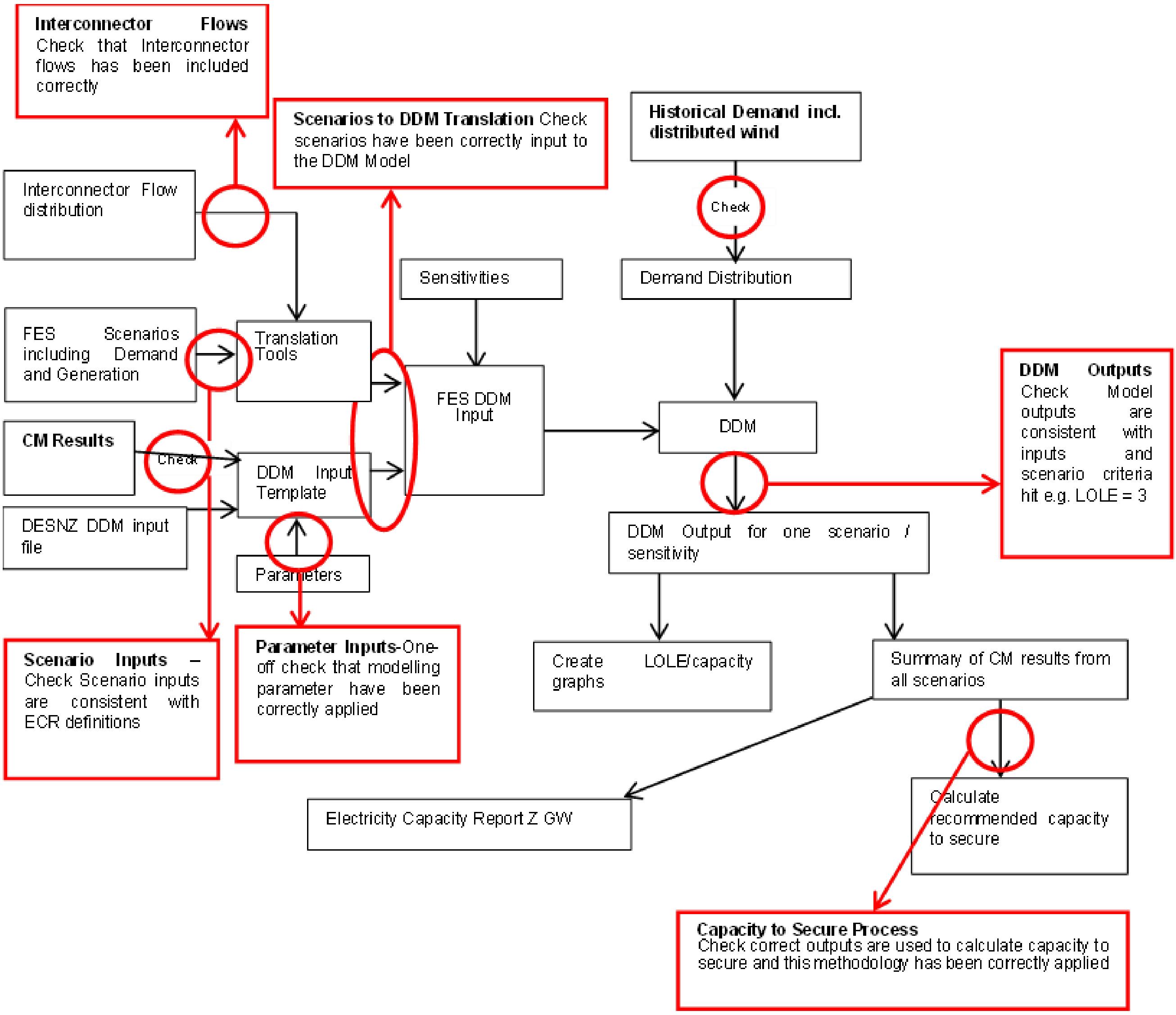
The high-level process and the points within the process where QA checks have been undertaken are shown in Figure 53.

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

[108] 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.)

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

Figure 53: QA Checks Process Diagram for each Target Year



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/ Historical 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 DESNZ, 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, 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 are consistent and robust. Sign off is then required at senior manager level. The assumptions and outputs will be published in the annual FES document in July 2023.

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

Scenarios to DDM Translation

The tool for translating the FES scenarios into DDM has been documented and available for scrutiny by DESNZ 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 DESNZ 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 DESNZ 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[110]
- A review of the code by PwC[111]
- Internal reviews by DESNZ

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[112]), were asked to ensure that the ESO was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between the 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 the 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.

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[110] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/65711/5427-ddm-peer-review.pdf

[111] See page 8 of https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/267616/Annex_G_-_Modelling_Quality_Assurance.pdf

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

A.11 Interconnector Modelling Assumptions

The following section presents assumptions used in PLEXOS for the interconnector de-rating factor calculation and a commentary on the materiality of these assumptions.

A.11.1 PLEXOS Assumptions

The data in Table 27 gives a high-level overview of some of the assumptions made in PLEXOS. This covers both input data and modelling assumptions.

Table 27: PLEXOS Modelling Assumptions

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
GB plant capacity	ESO Future Energy Scenarios	By unit for transmission and larger embedded. Aggregated for smaller embedded	
Europe plant capacity	Baringa	By unit for transmission, aggregated for embedded	
Plant capacity is net capacity	ESO FES / Baringa	N/A	Modelling uses net output instead of gross output
GB annual demand	ESO FES	Annual TWh figure	PLEXOS has the capability to model flexible demand and was included for ECR 2023
Europe annual demand	Baringa	Annual TWh figure	
Thermal plant availability profiles	Baringa	Mostly monthly or monthly business day/non-business day. Some quarterly or weekly	
Renewable plant output profiles	Baringa	Mostly hourly, some hourly by month pre-2006	Reduced resolution pre-2006, currently data from 1985 – 2019 is used
Storage plant availability profiles	Baringa	Monthly	Some new storage types have little or no historical data
Hydro plant availability profiles	Baringa	Weekly	Only has data for a limited number of weather years, uses a default otherwise
GB – Europe interconnector capacity	ESO FES	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling
Europe – Europe interconnector capacity	Baringa	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling
Interconnector loss rates	ESO FES	By interconnector (variable by direction if desired)	
GB demand profiles	ESO FES / Baringa	Annual historical hourly, split by demand type	Data for 1985 – 2018 currently used
Europe demand profiles	Baringa	Annual historical hourly, split by demand type	Data for 1985 – 2018 currently used

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
Short-term storage parameters	Baringa	By unit	Includes MWh capacity and round-trip efficiency
Flows from non-modelled markets	Energy Exemplar	Hourly	Currently assumed to be zero (float)
Generation (after interconnector losses are considered) is always cheaper than load loss	ESO	N/A	Value of Lost Load set to €3,000 / MWh
Lost load in Europe is prioritised over lost load in GB	ESO	N/A	
Most markets are modelled as a single node (with no internal transmission constraints)	Energy Exemplar	N/A	Currently Denmark, Italy, Norway and Sweden are modelled as more than one market

A.11.2 Markets Modelled

Table 28 shows the markets that are modelled in PLEXOS. 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 28: Markets Modelled in PLEXOS

Country	Number of Markets Modelled	Notes
Austria	1	
Belgium	1	
Czechia	1	
Denmark	2	Excludes Kriegers Flak offshore wind as a separate market
France	1	Does not include Corsica
Finland	1	
Germany	1	Excludes 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	7	
Luxembourg	1	
Netherlands	1	
Norway	5	

Country	Number of Markets Modelled	Notes
Poland	1	
Portugal	1	
Slovenia	1	
Spain	1	Mainland only modelled
Sweden	4	
Switzerland	1	

A.11.3 Materiality Commentary

This section is a commentary on the some of the assumptions made in PLEXOS 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 PLEXOS. However, it is included in this document to give an indication of the thought processes used by the ESO 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 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 the ESO varying AC interconnector losses which demonstrates that the interconnector de-rating factors are not very sensitivity to changes in this parameter.

Random outages – PLEXOS has allowed us to include random outages for small, aggregated thermal units along with named units utilising detailed parameter options. Historical average availabilities are used to create a deterministic percentage for all other generator types (intermittent renewable, storage and hydro) including weather impacts.

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 PLEXOS and therefore may over-estimate the capacity available in a market.

Plant availability profiles – PLEXOS allows for plant availability to have a scheduled component dependant on known dates alongside general parameters (rather than a fixed profile). We have fixed this annualised schedule across our detailed modelling and added more restrictive profiles, for example for French nuclear, where the historical data is more pertinent.

Internal transmission constraints – Excepting those countries that are modelled as more than one market in Table 28, no internal transmission constraints are modelled in PLEXOS. 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 – PLEXOS 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 how we modelled this in previous years is that it ignored flexible demand types. This was 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 excluded demand types that can discharge back into the grid, such as in vehicle-to-grid. This was a known problem expected to become more of an issue as this technology becomes more widespread. This flexible demand can be modelled in PLEXOS and used for the first time in 2023 ECR.

A.12 Interconnector Derating Factor Percentiles

Average annual interconnector derating factors for each scenario and sensitivity have been calculated as the average of the distribution of hourly derating factors over 200 random outage cases. In this year's ECR we have supplemented these average derating factors with the percentiles of each distribution building on the work from last year's ECR. The motivation behind the publication of percentiles is that distinctly different distributions can possess similar averages whilst displaying a markedly different risk profile to consumers.

Take for instance a Gaussian like distribution centred on a derating factor of 50 per cent with a standard deviation of 10 per cent. Our understanding of Gaussian statistics tells us that 68.2 per cent of all derating factors lie within the range of 40-60 per cent etc.

Now consider a bimodal distribution where derating factors are distributed equally between zero per cent and 100 per cent. Both distributions have an average of 50 per cent but the latter distribution presents significantly more risk to consumers because the probability of zero interconnector flow is much greater in a world governed by this distribution.

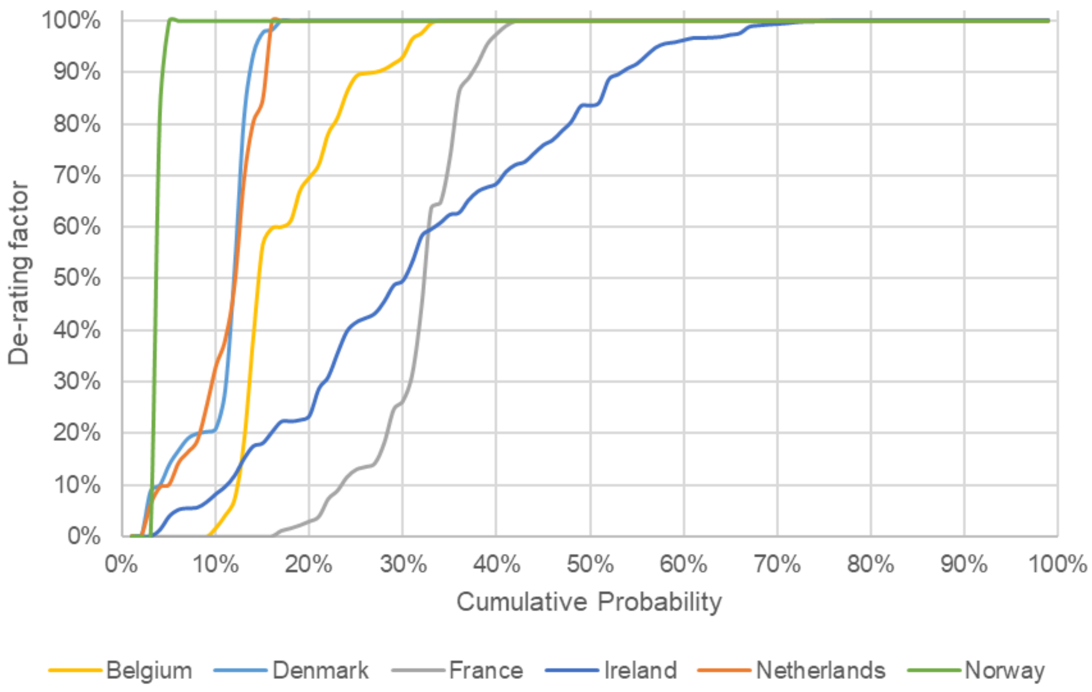
In Figure 54 we show percentile plots for each country in the Base Case and European Central Case. Percentiles are plotted as a function of interconnector derating factor. One can interpret the x-axis as the estimated probability of seeing an hourly derating factor of less than or equal to the corresponding value on the y-axis. The same characteristic curve is seen for all derating factor percentile plots. The shape of the curve indicates that derating factors are distributed within highly bimodal distributions with modes centred on zero and one hundred. This is indicative of world in which the interconnector in question is either importing to Great Britain at the full capacity in a given hour or not at all. Intuitively this is telling us that when Great Britain has a stress period, other neighbouring countries in Europe may also be experiencing a stress period at the same time, meaning imports are unavailable; if neighbouring countries are not experiencing a stress period, there is sufficient capacity in Europe to provide full imports to Great Britain, driven by high scarcity prices here.

The detailed view of the underlying derating factor distributions offered by percentiles allows us to consider whether the mean average is an appropriate description of central tendency to measure interconnector derating factors. A disadvantage of the mean is that it is biased to the presence of outliers, i.e. the presence of a small number of data points that are much larger or smaller than is typical for the distribution can significantly skew the measurement. Often the median (50th-percentile) is used as an outlier resistant measure of central tendency. Another approach takes the mean over a range limited by the percentiles that include the vast majority of data points and omit as many outliers as possible. An alternative approach is simply to take a percentile other than the median but this is usually an arbitrary choice.

The nature of the percentile plots presented here is much like the second case described above, i.e. there is significant risk of zero imports during any given hourly period within a stress event. Therefore, any measure of central tendency must convey this risk. In most cases the probability of seeing a derating factor of 100 percent is much higher than the probability of seeing a derating factor of zero. Taking the median to describe the central tendency often results in interconnector derating factors of 100 per cent, which clearly does not reflect the risk of zero flows. The alternative approach described above, taking the mean over a range limited by a lower and upper percentile would be unhelpful here as would mean clipping data from the two prominent modes.

The point here is really that while the two modes of these distributions are imbalanced, neither is a set of outlying points and both lie at the extreme opposite ends of the distributions. The mean average should therefore naturally be weighted towards an appropriate level of risk and is a good measure of central tendency for distributions of this nature.

Figure 54: Base Case & European Central Case interconnector de-rating factors – cumulative probability



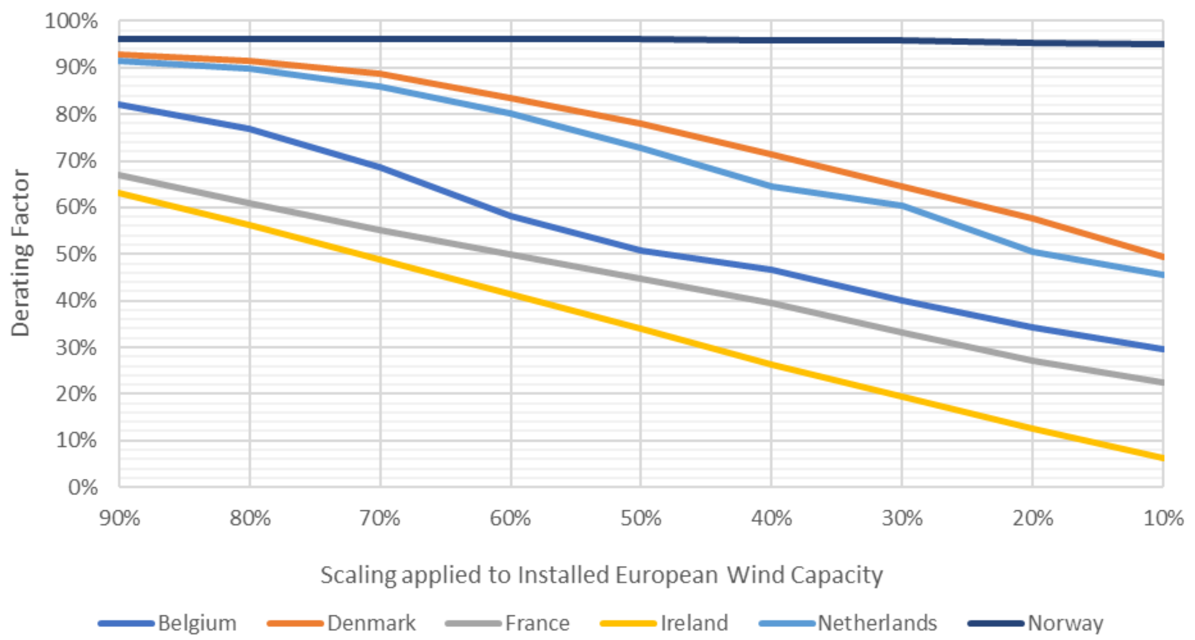
A.13 Interconnectors and European wind drought

The following does not form part of our main analysis and sensitivities, or our interconnector derating ranges.

In our interconnector modelling outlined in Section 5.2 Interconnectors we model 34 weather years to capture weather effects on interconnector availability. While this covers a range of weather conditions, and is focused on times of GB system stress, there is no sensitivity purely covering weather risk. These risks, low wind across Europe during dark hours, can be prolonged and tail events.

To illustrate this, we have considered the impact of reduced wind capacity in Europe in our model while following the same methodology as for all our other sensitivities. This means that we have reduced the wind output *after* considering which hours to model in detail – the hours modelled is consistent across all our sensitivities. This reduced wind capacity represents a reduction in wind output due to some combined weather event (for example a high-pressure system over the North Sea). It should be stressed that this is illustrative and does not consider the meteorological event(s) that would need to occur to produce this lull, nor the correlation effects on demand or other sources such as long-term storage.

Figure 55: Base Case interconnector derating for reduced wind output sensitivity. Steps of 10% reduction



In the extreme case (a 90% reduction in wind output across Europe) there is still capacity from Denmark and the Netherlands half the time while Ireland and France have severely reduced interconnector export capacity. However, this masks that during the hours of unavailable interconnector capacity, Europe is in marked system stress too extreme to handle. It is unlikely this would occur (given the simultaneous conditions across a large geographic area) but could also be coupled with a hash cold period spiking demands and producing extreme outages. This type of event was seen in Texas in 2021 albeit more extreme.

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