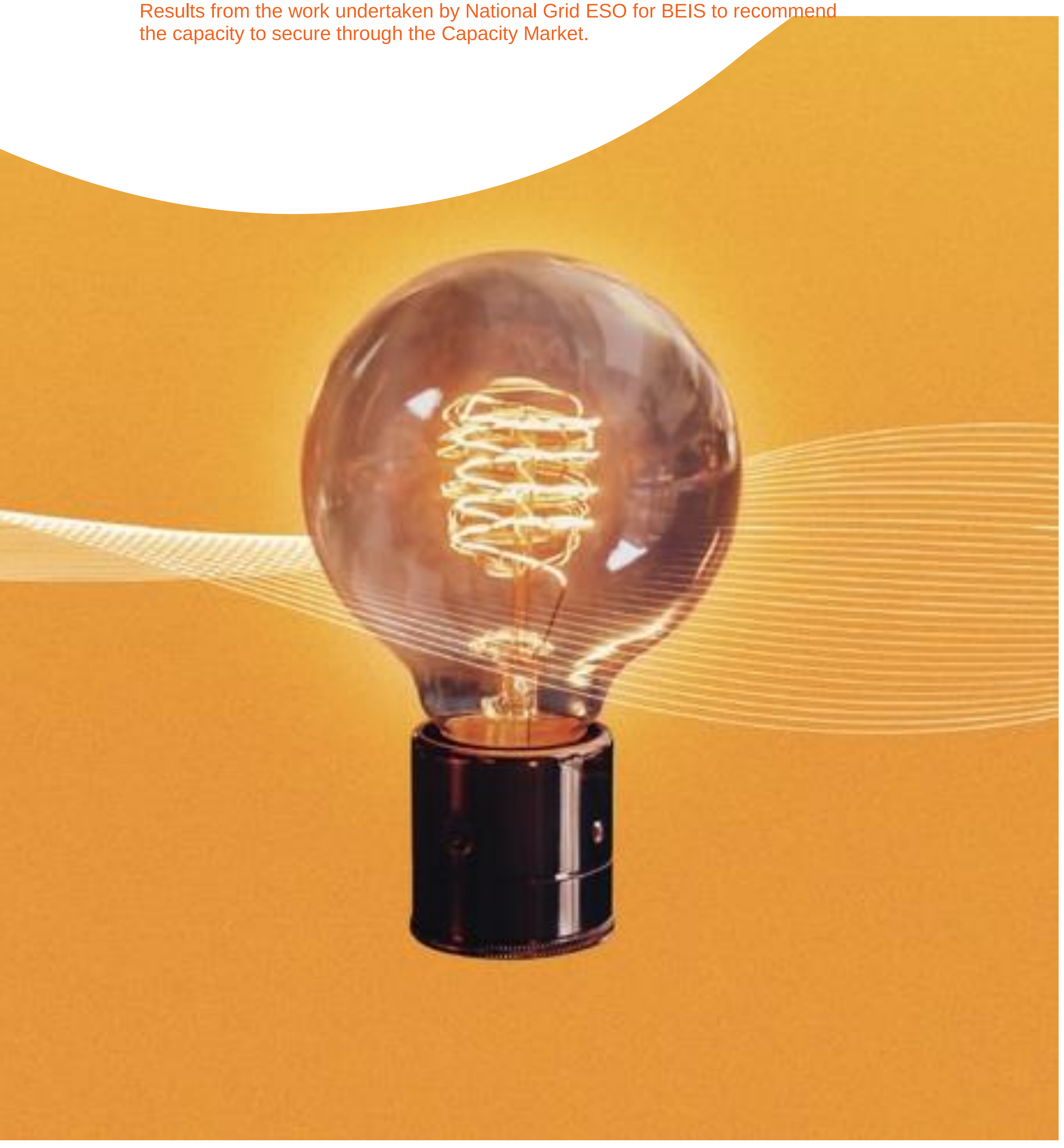
National Grid ESO
Electricity Capacity Report

31 May 2019 (submitted to Department for Business, Energy and Industrial Strategy)

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



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National Grid ESO
Electricity Capacity Report

1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling analysis undertaken by National Grid ESO in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision by the Government on the amount of capacity to secure through the Capacity Market (CM) auctions for delivery in 2020/21 and 2023/24. As the Government is currently considering replacing the suspended T-4 auction for delivery in 2022/23 with a T-3 auction, National Grid ESO has also analysed this proposal and provided a provisional recommendation.

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

National Grid ESO has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2018 process and adjusted and improved this year's analysis appropriately to try to address their feedback. In addition, there has been a series of workshops[3] with Department for Business, Energy and Industrial Strategy (BEIS), PTE and Office of Gas and Electricity Markets (Ofgem) to enable them to scrutinise the modelling approach and assumptions utilised.

Chapter 2 of this report describes the modelling approach including the tools used and enhancements made for this year's analysis. Chapter 3 covers the scenarios and sensitivities modelled. Chapter 4 details the de-rating factors for generating technologies, storage, DSR and interconnected countries. Chapters 5 to 7 contain results from the scenarios modelled and the recommended capacity to secure for the 2020/21 T-1, proposed 2022/23 T-3 and 2023/24 T-4 auctions respectively. Finally, the Annex contains links to or details on demand and generation methodology / assumptions, the modelling approach, matrix of development projects, station availabilities, ineligible capacity, Reserve for Response, storage assumptions, least worst regret approach and the quality assurance process.

1.1 Results and Recommendations

National Grid ESO has modelled a range of capacity options based around meeting the Reliability Standard in different combinations of credible scenarios and sensitivities. The assumption is that the Future Energy Scenarios (FES) and the Base Case will cover uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), storage, interconnection capacity and generation. The sensitivities cover uncertainty in non-delivery, station peak availabilities, weather, wind levels and peak demand forecast range (based on the Peak National Demand Forecasting Accuracy (DFA) Incentive[4]). Our analysis assumes continued market harmonisation between the

[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/723234/Panel_of_Technical_Experts_2018_Report_on_the_ECR.pdf
[3] Meetings took place up to November 2018 and then again in May 2019.
[4] See Special Condition 4L at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

UK and Europe once the UK has left the European Union; for example, the UK continues to participate in the Internal Energy Market or similar future arrangements are developed.

Scenarios & Base Case

- Base Case (BC)
  [Five Year Forecast to 2023/24, then Steady Progression from 2024/25 onwards]
- FES Community Renewables (CR)
- FES Two Degrees (TD)
- FES Steady Progression (SP)
- FES Consumer Evolution (CE)

To provide the reference case, which is being used to apply sensitivities, a Base Case has been utilised. For the DFA incentive years up to 2023/24, this consists of a forecast of demand and a generation background which aligns with our DFA Incentive and aims to reduce the likelihood of over or under securing of the capacity, thereby minimising the associated costs to consumers.

Each of the sensitivities is considered credible and is evidence based i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. Section 3.10 describes each sensitivity and how it has been implemented.

The decision on the target capacity to secure is made by a cost optimised Least Worst Regret (LWR) methodology. As per previous ECR analysis, it uses a cost of capacity of £49/kW/year[5] net CONE (Cost of New Entry) and an energy unserved cost of £17,000/MWh to select a scenario/sensitivity combination from which the recommended capacity to secure is derived. Note that the Government's Reliability Standard[6] was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT).

1.1.1 2020/21 T-1 Auction Recommendation

Results

The outcome of the Least Worst Regret (LWR) calculation applied to all of the scenarios and sensitivities is a capacity to secure for 2020/21 of -1.3 GW derived from the requirement of the nearest Base Case sensitivity to the value selected by the LWR tool. As per the conclusion of the T-1 LWR development project (see section 2.5.2), since the outcome of the LWR analysis is a negative target capacity, we recommend a target of **0 GW**.

In general, when compared to the analysis for 2020/21 in the 2016 ECR that ultimately led to the 0.6 GW set aside by the Secretary of State for the T-1 auction, the 2019 ECR LWR outcome for 2020/21 is 1.9 GW lower than the 0.6 GW set aside. This net difference is the result of 4.5 GW of increases offset by 6.4 GW of decreases since the 2016 ECR.

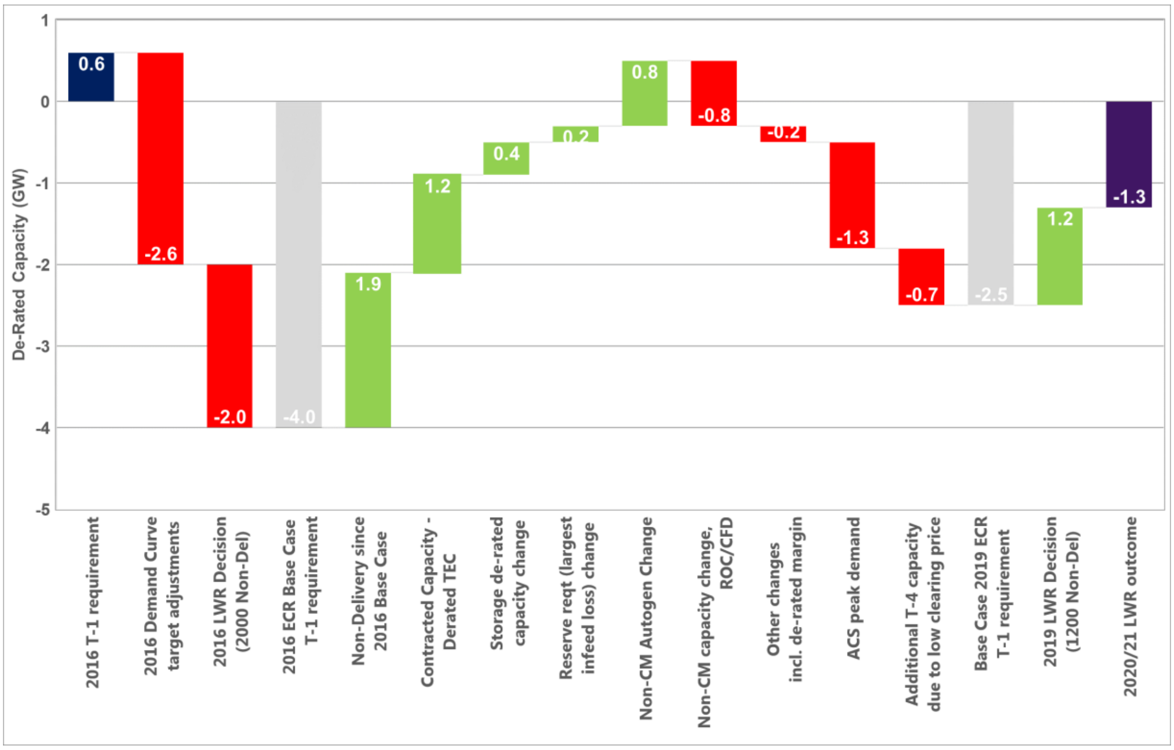
[5] As outlined in the EMR Stakeholder bulletin issued on May 14th 2014
[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

The increases result from non-delivery (units in the 2016 Base Case awarded contracts in the 2018/19, 2019/20 and 2020/21 T-4 auctions covering 2020/21 that are now known not to be able to honour their contracts), revised de-rating factors for duration-limited storage contracted in the 2020/21 T-4 auction, the contracted capacity from previous T-4 auctions being greater than the de-rated TEC, higher reserve for largest infeed loss and lower levels of assumed opted-out or ineligible autogeneration than the 2016 Base Case.

The decreases arise from a change in the scenarios and sensitivities modelled resulting in a different LWR outcome than in 2016, a lower peak demand for 2020/21, a reduction due to over-securing in the 2020/21 T-4 auction, a reduction resulting from higher non-CM renewable capacity and a small net reduction due to other changes. In addition, the demand curve adjustments made in 2016 following prequalification for the T-4 auction [to account for changes in ineligible / opted-out and operational capacity from the 2016 Base Case - see 5.3.3 for more details] are no longer relevant for the T-1 auction as the prequalification for the T-1 auction has not yet taken place and the 2019 Base Case generation assumptions are different to the 2016 Base Case assumptions.

Figure 1 shows how the original 0.6 GW set aside for the 2020/21 T-1 auction (derived from the 2000 MW non-delivery sensitivity) has changed into a LWR outcome of -1.3 GW (derived from the 2019 Base Case 1200 MW non-delivery sensitivity) as a result of the net decrease described above.

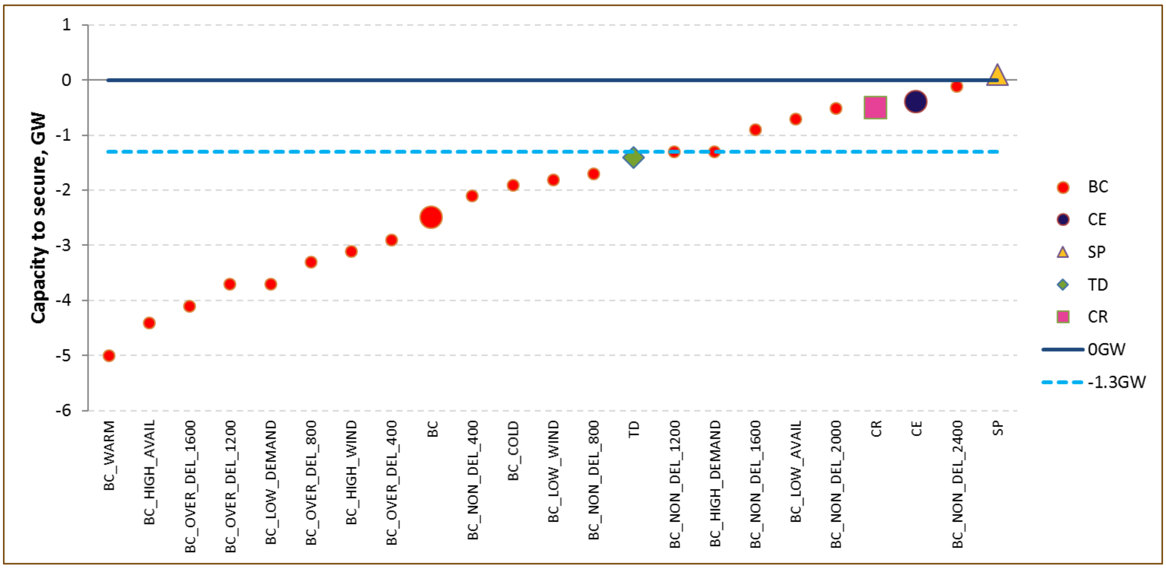
Figure 1: Comparison with original 2020/21 T-1 requirement (de-rated)



Note: intermediate totals in grey above show requirements for 2016 Base Case and 2019 Base Case

Figure 2 illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret outcome (-1.3 GW) and recommendation (0 GW). Note that the FES scenarios have a less negative requirement than the Base Case due to additional non-delivery assumed in these scenarios and / or higher peak demand.

Figure 2: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2020/21



Recommendation

Although we recommend a target of 0 GW for the T-1 auction, the decision on whether to run an auction will be taken by the Secretary of State. If the auction is run, the final auction target will also be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the final T-1 auction target, a number of adjustments to the initial value (denoted by t GW) may be required which are detailed in Chapter 5.

Therefore, the final auction target in the 2020/21 T-1 auction could be:

- t GW minus any adjustments.

1.1.2 2022/23 T-3 Auction Provisional Recommendation

Results

The outcome of the LWR calculation applied to all of National Grid SO's scenarios and sensitivities is a provisional recommendation of the capacity to secure for 2022/23 of **45.4 GW** derived from the requirement of the Base Case 400 MW non-delivery sensitivity. This provisional recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The provisional recommendation also excludes any capacity secured for 2022/23 in earlier T-4 auctions that is assumed in the Base Case.

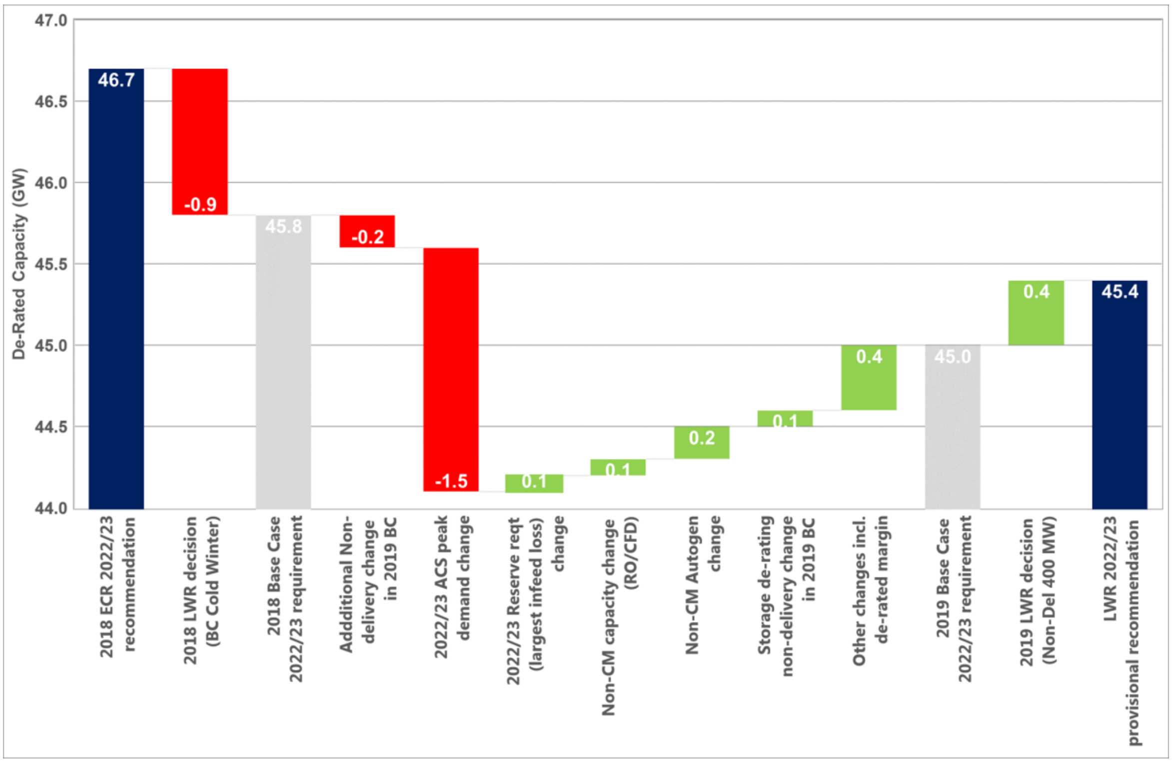
In general, when compared to the analysis for 2022/23 in the 2018 ECR, the 2019 ECR provisional recommendation for 2022/23 is 1.3 GW lower. This net difference is the result of 0.9 GW of increases offset by 2.2 GW of decreases since the 2018 ECR.

The increases result from a small increase in reserve for largest infeed loss, lower non-CM renewable capacity, lower assumed opted-out or ineligible autogeneration, a small change in estimated de-rated storage awarded multi-year contracts in 2020/21 and a small net increase due to other changes.

The decreases arise from a change in the scenarios and sensitivities modelled resulting in a different LWR outcome, no additional distributed generation (DG) non-delivery in the 2019 Base Case (compared to some in 2018), and a lower peak demand for 2022/23 than in 2018 (due to reduced EV charging at peak, reduced residential demand, change in annual to peak correlation and the residential halogen lighting ban – see Section 3.3 for more details).

The following waterfall chart, Figure 3, shows how the original 46.7 GW requirement for the 2022/23 T-4 auction (derived from the 2018 Base Case cold winter sensitivity) has changed into a provisional recommendation of 45.4 GW (derived from the 2019 Base Case 400 MW non-delivery sensitivity) as a result of the 1.3 GW net reduction described above.

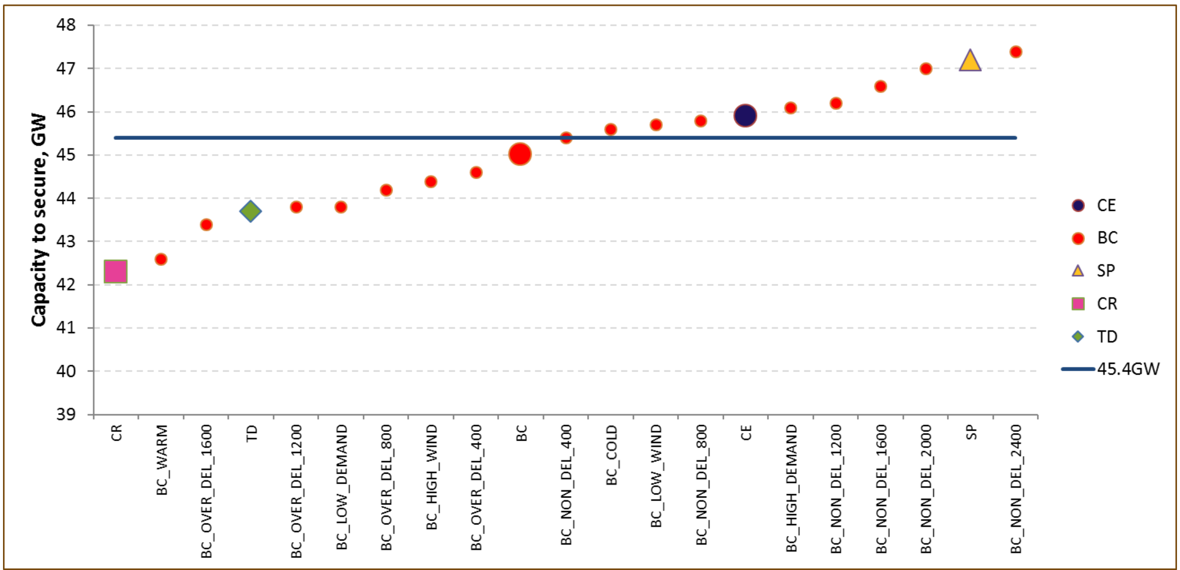
Figure 3: Comparison with recommended 2022/23 T-4 requirement in 2018 ECR



Note: intermediate totals in grey above show requirements for 2018 Base Case and 2019 Base Case

Figure 4 illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret provisional recommendation.

Figure 4: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2022/23



Recommendation

The provisional recommendation in this report will not necessarily be the capacity auctioned. If the Secretary of State decides to hold a T-3 auction, the target capacity will also be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the National Grid ESO provisional capacity auction requirement, a number of adjustments to the total provisional recommended figure may be required which are detailed in Chapter 6.

Therefore, the provisional recommendation of the total capacity to secure through the 2022/23 T-3 auction will be:

- 45.4 GW minus any adjustments.

1.1.3 2023/24 T-4 Auction Recommendation

Results

The outcome of the LWR calculation applied to all of National Grid SO's scenarios and sensitivities is a recommended capacity to secure for 2023/24 of **44.7 GW** derived from the requirement of the Base Case cold winter sensitivity. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2023/24 in earlier T-4 auctions that is assumed in the Base Case.

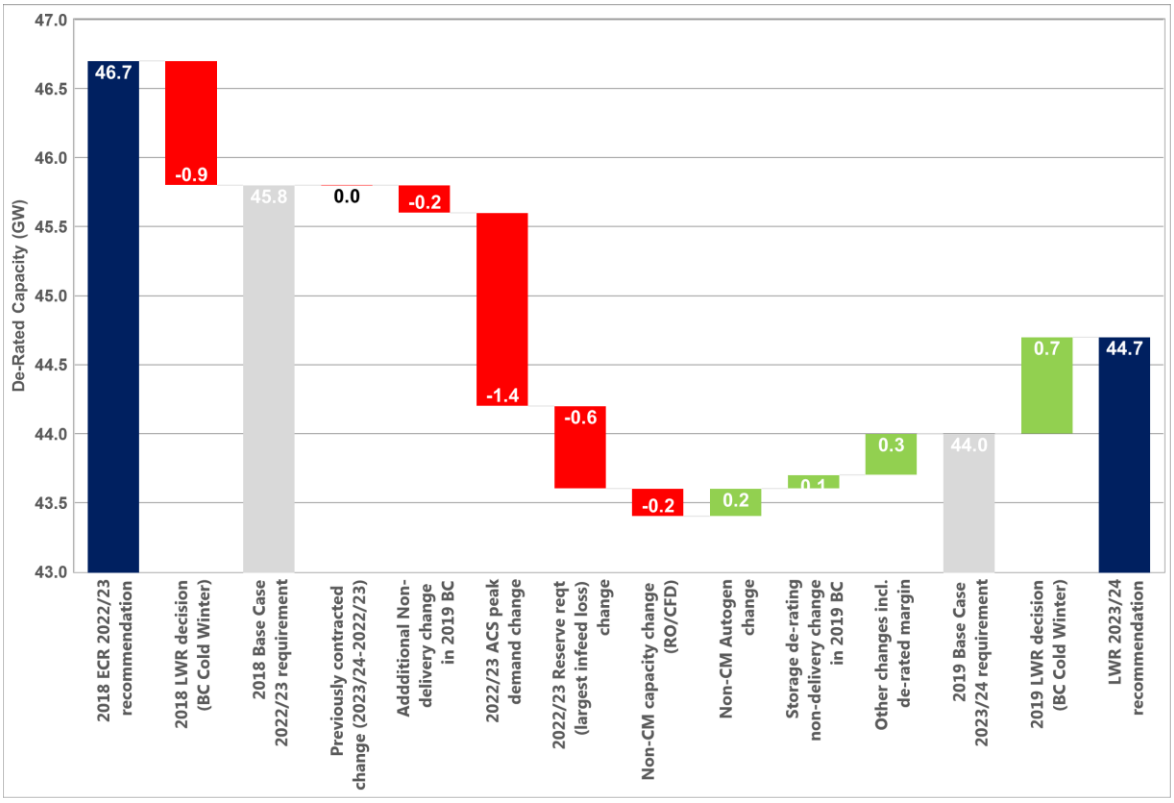
In general, when compared to the analysis for 2022/23 in the 2018 ECR, the 2019 ECR recommendation for 2023/24 is 2.0 GW lower. This net difference is the result of 0.6 GW of increases offset by 2.6 GW of decreases since the 2018 ECR.

The increases result from lower assumed opted-out or ineligible autogeneration, a small change in estimated de-rated storage awarded multi-year contracts in 2020/21 and a small net increase due to other changes.

The decreases arise from a reduced differential of the LWR outcome to the Base Case, a decrease in reserve for largest infeed loss, higher non-CM renewable capacity, no additional distributed generation (DG) non-delivery in the 2019 Base Case (compared to some in 2016), and a lower peak demand for 2023/24 than for 2022/23 in 2018 (due to reduced EV charging at peak, reduced residential demand, change in annual to peak correlation and the residential halogen lighting ban – see Section 3.3 for more details).

The following waterfall chart, Figure 5, shows how the original 46.7 GW requirement for the 2022/23 T-4 auction (derived from the 2018 Base Case cold winter sensitivity) has changed into a recommended requirement of 44.7 GW (derived from the 2019 Base Case cold winter sensitivity) as a result of the 2.0 GW net reduction described above.

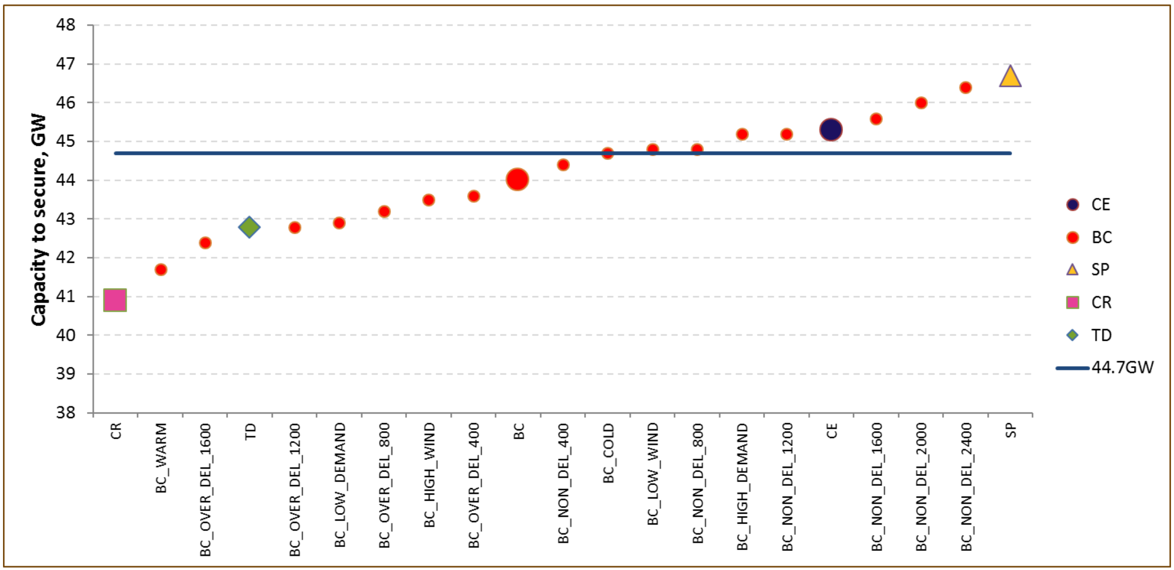
Figure 5: Comparison with recommended 2022/23 T-4 requirement in 2018 ECR



Note: intermediate totals in grey above show requirements for 2018 Base Case and 2019 Base Case

Figure 6 illustrates the full range of potential capacity levels (from the scenarios and sensitivities) and identifies the Least Worst Regret recommended capacity to secure.

Figure 6: Least Worst Regret capacities to secure compared to individual scenario/sensitivity runs – 2023/24



Recommendation

The recommended target capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the National Grid ESO recommended capacity auction requirement, a number of adjustments to the total recommended figure may be required which are detailed in Chapter 7.

Therefore, the recommended total capacity to secure through the 2023/24 T-4 auction will be:

- 44.7 GW minus any adjustments.

1.2 Interconnected Countries De-rating factor Ranges

Table 1 and Figure 7 show the modelled country ranges to inform the choice of de-rating factors for the 2020/21 T-1 auction, the proposed 2022/23 T-3 auction and the 2023/24 T-4 auction for all existing and potential interconnected countries.

These modelled ranges are based around the modelling we have done using BID3, our pan-European market model. This year, BEIS have made changes to the interconnector de-rating methodology to remove the requirement for a historical ‘floor’ to constrain the de-rating factors.

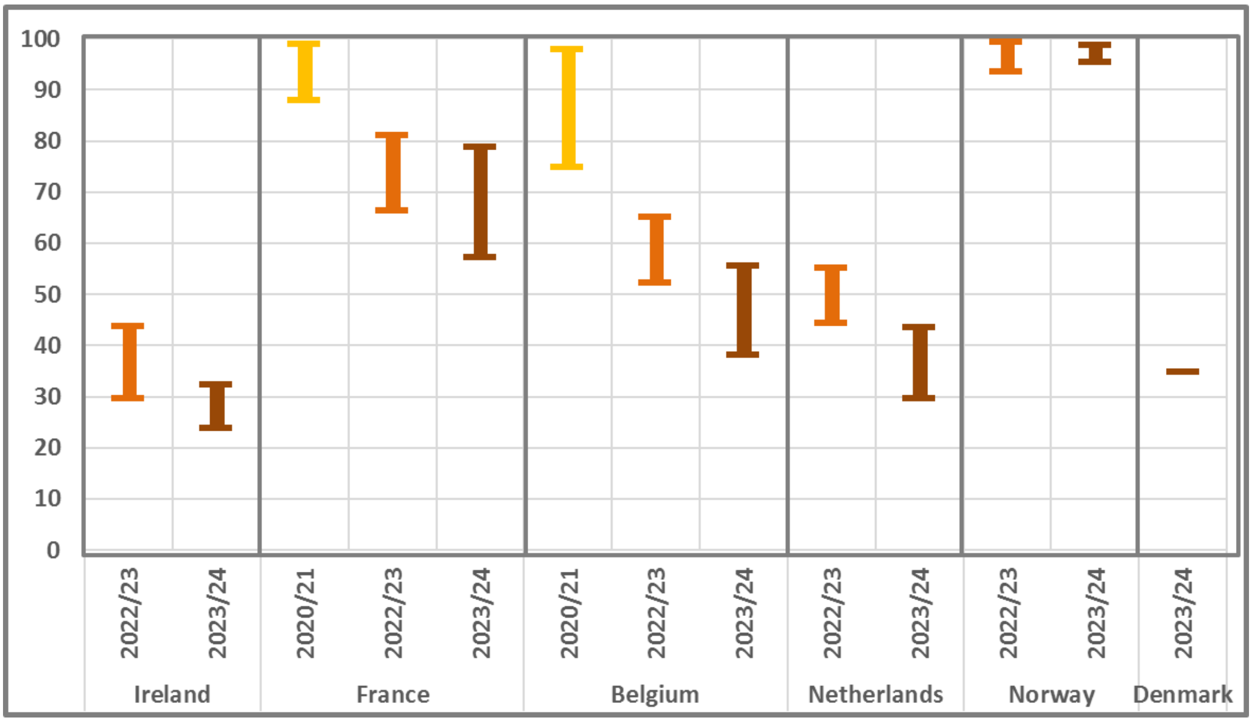
This year it has not been possible to use the FES scenario data without adjusting demand due to the lack of stress periods in Great Britain. BID3 is an economic model so if Great Britain has a surplus of generation the model may export and not import. It would not provide any information on the potential for imports. Therefore, demand in Great Britain was increased to ensure that enough stressed periods were available to represent 3 hours LOLE. As a 30-year history was modelled, this is 3 hours * 30 years = 90 hours. The range has been selected from the maximum and minimum of these results.

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

Table 1: Modelled country ranges

Country	Delivery Year	Low	High
Ireland	2022/23	30	44
	2023/24	24	32
France	2020/21	88	99
	2022/23	66	81
	2023/24	57	79
Belgium	2020/21	75	98
	2022/23	52	65
	2023/24	38	56
Netherlands	2022/23	44	55
	2023/24	30	44
Norway	2022/23	93	99
	2023/24	95	99
Denmark	2023/24	35	35

Figure 7: Interconnector de-rating factor ranges



1.3 National Grid ESO Analysis Delivery Timeline 2019

The process and modelling analysis has been undertaken by National Grid ESO with ongoing discussions with BEIS and Ofgem during the development, modelling and result phases. Meetings to present work to BEIS's PTE happened during Autumn 2018 and again in Spring/Summer 2019.

The work was carried out between September 2018 and May 2019 and builds on the analysis that was undertaken for the previous ECRs. In addition to the analysis around the recommended capacity to secure, the report also presents analysis on the de-rating factors for interconnected countries, conventional, storage and intermittent renewables technologies for use in the auctions.

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

- Development plan produced in September 2018
- Development projects phase October 2018 to February 2019
- Production plan developed in February 2019
- Modelling analysis March to May 2019
- National Grid ESO's ECR sent to BEIS before 1st June 2019
- Publication of ECR in line with BEIS publishing auction parameters in early July 2019

2. The Modelling Approach

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

2.1 High Level Approach

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

What is the volume of capacity to secure that will be required to meet the security of supply reliability standard of 3 hours Loss of Load Expectation (LOLE)[7]?

In order to answer this question, it was agreed, following consultation with BEIS and their PTE, that the Dynamic Dispatch Model (DDM)[8] was an appropriate modelling tool. This maintains consistency with the energy market modelling work undertaken by BEIS. The DDM has the functionality to model the Capacity Market and it should also be noted that, when compared to National Grid ESO's capacity assessment model, as utilised for the Winter Outlook, the DDM has been shown to produce the same results, given the same inputs.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[9], and sensitivities around a Base Case which cover a credible and broad range of possible futures. See Chapter 3 for details of the scenarios and sensitivities used in the modelling.

The scenarios are comprised of assumptions around:

- Peak demand – This is unrestricted i.e. no Demand Side Response or Triad avoidance has been subtracted
- Generation capacity – Both transmission connected and distributed (within the distribution networks)
- Interconnector assumptions – Capacity assumptions (note that flows at peak are modelled directly within DDM)

Sensitivities are then created around the Base Case to ensure consistency with National Grid ESO's Peak National Demand Forecasting Accuracy (DFA) Incentive[10].

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

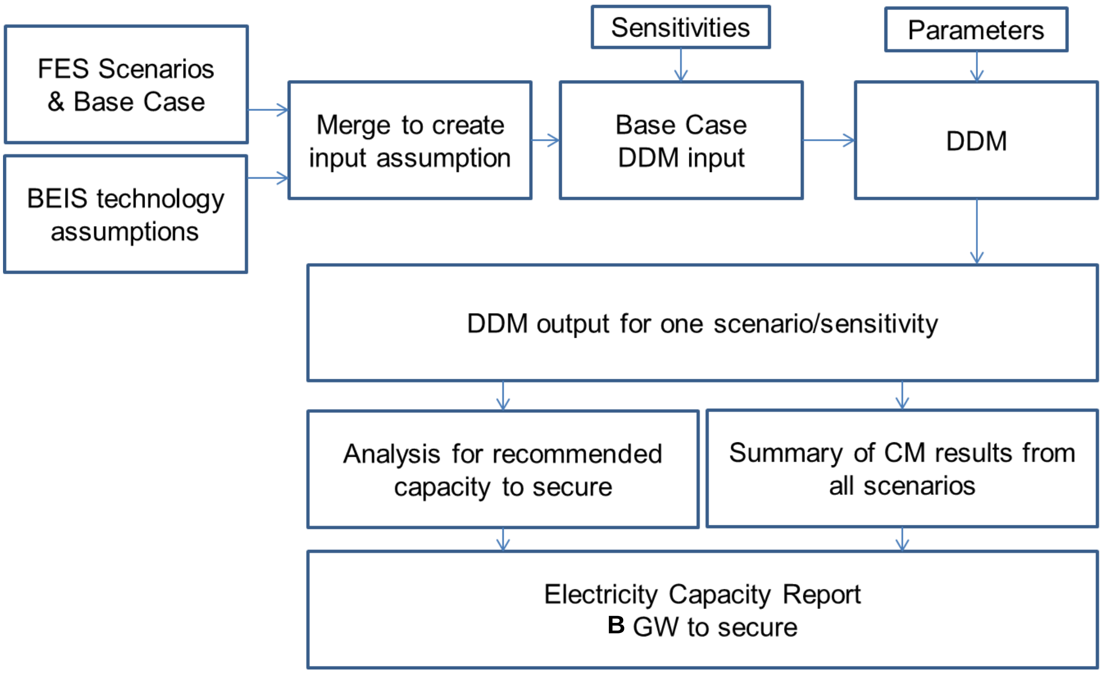
[8] DDM Release 5.1.23.3 was used for this analysis

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

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

The modelling process, as shown in Figure 8, determines a capacity to secure and provides a view of capacity which is expected to be delivered outside of the Capacity Market. Each of the scenarios and sensitivities produces a capacity to secure for those given circumstances and these are considered together to produce a recommended capacity to secure in the Capacity Auctions for 2020/21 and 2023/24 and provisional recommendation for 2022/23. Links to the detail describing this process can be found in Annex A.5.

Figure 8: Process flow chart of approach to calculate target capacity to secure from individual scenario/sensitivity runs



2.2 DDM Outputs Used in the ECR

For the purpose of the ECR, the key outputs utilised from the DDM for each year modelled from 2020/21 to 2033/34 are the aggregate capacity values, specifically:

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

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

In addition to the aggregate capacity values, for the purpose of calculating the recommended capacity to secure for 2020/21 and 2023/24 and provisional recommendation for 2022/23, the Least Worst Regret tool also utilises the expected energy unserved (EEU) and LOLE values for potential de-rated capacity levels in both years (see Chapters 5, 6 and 7 for more details).

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

2.3 Stakeholder Engagement

National Grid ESO has a well-established and extensive consultation process which is followed on an annual basis to create the Future Energy Scenarios (FES). The process incorporates a summer seminar, webinars, workshops and bilateral meetings with our stakeholders to ensure we are receiving up to date information and feedback for our scenarios. The content of the FES is driven by stakeholder feedback; this results in a range of holistic, credible and plausible scenarios. We publish the outputs of our consultation process each year in the FES Stakeholder Feedback document[11] in line with our licence condition. The document, published annually in February, shows how stakeholder feedback influences the framework, scenario format and the content of the model inputs that underpin the scenarios. This document contains details of topic specific feedback that we have received from stakeholders and how we have taken this forward.

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

2.4 High Level Assumptions

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

2.4.1 Demand and Generation

The starting point for the DDM input modelling assumptions was the set of assumptions used in the latest BEIS modelling e.g. assumptions behind generation levelised costs. However, the key inputs/assumptions are taken by aligning the modelling to the new 2019 FES scenarios and agreed sensitivities. The key assumptions are those that materially affect the capacity to secure, these are:

- Demand Forecasts
    - Peak demand
    - Annual demand forecasts
- Generation Capacity
    - Capacity eligible for the Capacity Market
    - Capacity outside the Capacity Market (including capacity secured via previous auctions)
    - Capacities of existing and new interconnectors

For a detailed breakdown of these key input assumptions see the Annex A.4.

[11] http://fes.nationalgrid.com/media/1397/2019-stakeholder-feedback-document-published-v10-010319.pdf

2.4.2 Interconnector Assumptions

Interconnector potential flows are determined by probabilistic modelling in a similar way to generation technologies, i.e. based around a set of flow distributions obtained from our own pan-European electricity dispatch market modelling using BID3[12] (see 2.4.3.4 for further details).

In addition to this modelling work, National Grid ESO will provide modelled ranges of de-rating factors to apply for each connected country participating in the CM auction. See Chapter 4 for more detail around this process and the modelled de-rating factors ranges for each country.

2.4.3 Station Availabilities and De-rating Factors

This analysis has been split into four groups: firstly, for conventional generation, secondly intermittent generation, thirdly duration limited storage and then finally, interconnectors.

2.4.3.1 Conventional generation

Conventional generation capacity is not assumed to be available to generate 100% of the time, due to break downs and maintenance cycles. In order to determine what availability to assume for each generation type, National Grid ESO considers what has been delivered historically, based on the average on high demand days over the last seven winter periods[13]. This approach has been used by National Grid ESO in its entire medium to long term modelling, as well as being used for the EMR Delivery Plan and Ofgem's Capacity Assessment. This methodology is described in detail in the Capacity Market Rules 2.3.5.

2.4.3.2 Intermittent renewable generation

Intermittent renewable plants such as wind and solar run whenever they are able to, and so the availability of the fuel source is the most significant factor. When considering these plants, National Grid ESO looks to their expected contribution to security of supply over the entire winter period.

For wind, this is achieved by considering a history of wind speeds observed across GB, feeding in to technology power curves, and running a number of simulations to determine its expected contribution. This concept is referred to as Equivalent Firm Capacity (EFC). In effect, it is the level of 100% reliable (firm) plant that could replace the entire wind fleet and contribute the same to security of supply.

The wind EFC depends on many factors that affect the distribution of available wind generation. These include the amount of wind capacity installed on the system, where it is located around the country and the amount of wind generation that might be expected at periods of high demand. It also depends on how tight the overall system is, i.e. as the system gets tighter, the wind EFC increases for the same level of installed capacity as

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

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

there are more periods when wind generation is needed to meet demand rather than displacing other types of generation in the merit order. Please note that that the wind EFC is not an assumption of wind output at peak times and consequently should not be considered as such. For the Base Case wind EFC values calculated by the DDM, please refer to Annex A.4.4 of this document.

As demonstrated in a recent development project looking at renewable de-rating factors, Solar PV can make a small contribution to security of supply particularly if storage capacity is installed. A related development project also reviewed the de-rating factors used for solar (and storage) in the DDM so that the total [storage + wind + solar] fleet de-rated capacity in the DDM aligned to the combined (storage / wind / solar) fleet EFC calculated in the development project. The solar fleet EFC in the DDM is calculated using these solar de-rating factor estimates. Please refer to section 2.5.2 for details on these development projects.

The Government has recently made changes to allow wind and solar farms (which are not receiving support under low carbon support schemes, including the RO or CFD) to participate in the Capacity Market. The ECR presents proposed wind and solar de-rating factors in light of that decision being implemented (see Table 9)

Please note that while the total wind and solar fleet EFC is utilised for setting the target capacity, the de-rating factors proposed for any subsequent wind or solar farms participating in future auctions are based on incremental EFCs. For details on the method used to calculate these, please refer to our industry consultation conclusions document[14].

2.4.3.3 Duration limited storage

The market for battery storage is growing fast with many having won Enhanced Frequency Response (EFR) or Firm Frequency Response (FFR) ancillary service contracts and CM contracts for 2020/21, 2018/19 and 2021/22 auctions. During the second half of 2017 (in line with the first part of recommendation 28 in the 2017 PTE report), we undertook an extensive industry consultation on a proposed methodology for calculating appropriate de-rating factors for duration limited storage. The details of this method which utilises an Equivalent Firm Capacity approach and the resulting de-rating factors for the T-1 (2018/19) and T-4 (2021/22) auctions can be found in our final report[15]. This method has been re-run for this year's analysis utilising updated assumptions (see Annex A.6 for details) on the level of storage capacity and duration of that capacity as contained in the Base Case.

2.4.3.4 Interconnectors

In the DDM, we have modelled the contribution of interconnectors to GB at peak times in each scenario and delivery year by using a probabilistic distribution, defining the probability of each import / export level for a given level of net system margin. These

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

distributions were derived from our own pan–European market modelling (see Chapter 4). The DDM calculated an EFC for interconnection which was used as an estimate of the aggregate interconnector de-rated capacity. Note that the modelled de-rating factor for interconnection has no impact on the total de-rated capacity (including interconnection), required to meet the Reliability Standard. In the auction, interconnection capacity will compete with other types of new/existing eligible capacity to meet the capacity requirement.

2.4.3.5 Impact of availability assumptions

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

2.4.3.6 Feedback on approaches to calculating availabilities and de-rating factors

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

2.5 Development projects

The development project phase of the ECR was planned between September 2018 and the end of February 2019 and during this period a series of projects to potentially enhance the modelling process were undertaken. As part of this process we worked closely with BEIS and Ofgem to determine which projects to prioritise and then worked collaboratively with consultants to deliver against the plan.

2.5.1 Process for selecting which development projects to progress

A key element of this process are the recommendations from BEIS's PTE who identify a number of areas of research to be progressed which, when combined with National Grid ESO, BEIS and Ofgem's ideas, produce a long list of potential projects, far more than can be undertaken (see Annex A.3). Consequently, a method of prioritisation is required to determine which projects go ahead.

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

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

2.5.2 Key projects undertaken

In their 2018 report[16], the PTE made 5 new recommendations numbered 36 to 40, each of which was considered as a potential development project alongside others for prioritisation. The Annex A.3 contains a list of all the development projects considered and which ones were progressed based on their relative scores. Out of the 5 PTE recommendations:

- 36 (full description of the Base case which has been included in Chapter 3) & 37 (energy infrastructure information strategy which has been covered by our Distribution connected de-rating factor analysis and BEIS' Energy Data Taskforce) were progressed.
- 38 (wider ranges for demand) & 40 (Impact of strategic reserve on European markets) were considered as part of other projects e.g. demand ranges within the FES scenarios and for strategic reserve within the European scenarios utilised in our interconnector flow modelling (see Section 4.2.1).
- Only 39 (analysis of what caused historical stress events e.g. whether combinations of events caused such events) was not progressed due to the lack of historical stress events and therefore data to analyse.

This year's key development projects related to:

Base Case detailed description

A detailed description of the Base Case key assumptions and drivers has been included in the 2019 ECR (see Chapter 3) ensuring full transparency around this 5-year view which subsequently all the sensitivities are run off.

16 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/723234/Panel_of_Technical_Experts_2018_Report_on_the_ECR.pdf

Renewable technologies de-rating factors for participation in the Capacity Market

During the Autumn, we developed an approach for calculating de-rating factors for wind and solar technologies if they were to be allowed in future to participate in the Capacity Market auctions. This process involved extensive engagement with technical experts from the University of Edinburgh (Dr. Chris Dent, Dr. Stan Zachary and Dr. Amy Wilson) on matters relating to risk modelling with renewables and intermittent renewable technologies and from Reading University (Dr. Daniel Drew) on data input to weather modelling. We have also engaged with US based industry representatives via the IEEE Loss of Load Expectation Working Group and European system operators during 2018 to benchmark our proposed approach to other similar capacity markets treatment of intermittent technologies. Finally, we consulted the independent Panel of Technical Experts who subsequently endorsed our approach. This stakeholder engagement gave us confidence ahead of formally consulting industry that our proposed approach was representative of the state of the art in this area. This industry consultation took place in January 2019 with a workshop and written consultation with a conclusion / recommendation document published in late February. The conclusions document also addressed concerns raised by a couple of industry stakeholders regarding the stability of the proposed de-rating factors as more wind left the Renewables Obligation and entered the CM by illustrating how the de-rating factors remained stable and fit for purpose until well into the 2020s and would only need reviewing for auctions covering years around 2030.

The two main technologies to be considered were wind and solar which, similarly to the calculation of de-rating factors for limited duration storage, were based on an incremental Equivalent Firm Capacity approach. To model this, we developed the Unserved Energy Model (UEM) code within the DDM working with Lane Clark and Peacock (LCP) to specify the code enhancements required. Onshore and offshore wind power curves were also revised.

Details of this modelling work and final de-ratings can be found in our final consultation conclusions document[17].

Distribution network connected technologies de-rating factors

These technologies currently have de-rating factors based on the nearest equivalent Transmission connected generation technology, which as the generation mix evolves into the future with more flexible small plant connecting, this project was designed to check the appropriateness of this CM Rule.

The project was split into two phases with the first being the procurement of historical half hourly output data by site from Electralink and then analysing the data to ascertain the potential suitability of this data to calculate de-rating factors. The second phase was to develop a sound method for calculating on an ongoing basis de-rating factors for future CM auctions.

While the first phase identified that the output data, except for a few outliers which could be filtered out, proved reliable, the data on the capacity per site was problematic and as

[17] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf

things currently stand prevents sound de-rating factors from being calculated. Consequently, further data sources on the site and technology capacities will be required to enable the project to be progressed ahead of any industry consultation on a potential new method for calculating de-rating factors for distribution connected technologies that will ensure value of money for consumers.

Wind scaling factor

In 2016, academic consultants recommended a base wind scaling factor of 0.9 in the DDM modelling for the ECR. As a result, when constructing a wind distribution, wind generation on days of high daily peak demand is scaled back by the DDM. The scaling applied to the wind generation varies linearly from 100% on days with peak demands below 92% of the ACS value to 90% scaling on days with peak demands above 102% of ACS peaks. The academic consultants also recommended the inclusion of low wind sensitivity (using a low wind scaling factor of 0.8) as well as a high wind sensitivity (using a high wind scaling factor of 1.0).

This project reviewed the DDM wind scaling parameter for the Base Case, low and high wind sensitivities in light of the recent development project to calculate de-rating factors (and update EFCs) for solar and wind in the CM (see above) and in light of the revised onshore and offshore wind power curves. To do this, the DDM was run multiple times to find the base wind scaling factor value for which the DDM wind EFC had the best match to the UEM total wind fleet EFC for the target years in the 2018 ECR. The 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 in the UEM for the two target years.

The project concluded that a base wind scaling factor of 0.75 gave the best alignment to the UEM total wind fleet EFC across the two target years. This change (combined with the updates to solar and storage de-ratings) did not materially change the capacity to secure in the two target years. As a result of this project, we have used a base wind scaling factor of 0.75 for most of the DDM runs in the 2019 ECR. The wind scaling factor used in the low wind sensitivity runs in the 2019 ECR has also been changed accordingly to 0.5 while the scaling factor for the high wind sensitivity remained at 1.0, maintaining the symmetrical range around the base value for the low and high wind scaling factors.

Interconnector de-rating factors over time

Several contradictory studies have been published over the last twelve months commenting on the future pathway of de-rating factors for interconnectors. Consequently, we undertook some analysis to ascertain the likely pathway for connected countries given a set of ENTSO-E European demand and generation scenarios. This analysis confirmed the pathway is driven by the changing generation mix across Europe and the number of interconnectors. In summary across most ENTSO-E scenarios, Belgium, France and Netherlands saw reducing de-rating factors through the 2020s, whereas for Ireland and Denmark, it depended on the scenario being modelled and for Norway and Germany, de-rating factors remained stable across scenarios.

Participation of foreign generators in the CM

This project investigated the potential challenges that would need to be addressed before foreign generators could participate in the GB Capacity Market rather than calculating potential de-rating factors. Participation of foreign generators could have some notable advantages in theory, that if planned and managed well then could have valuable consumer benefits in due course. However, for this to work effectively, we would need a co-ordinated pan-European capacity adequacy assessment and remuneration scheme with GB represented as one of many localised regional reliability balance and constraint areas. This would mean a consistent, unified and agreed approach for sharing capacity resources and interconnection flows between regions during periods of common stress. The project concluded that the numerous challenges include:

- Standardisation of generation adequacy metrics, reliability standards and modelling approaches across Europe (although ENTSO-E have started the process of attempting to harmonise these)
- Derivation of and access to data to enable comparable station availabilities and technology de-rating factors
- Market structure diversity and system operational differences during stress events
- Derivation of intermittent generators Equivalent Firm Capacity and thus de-rating factors
- CM eligibility criteria across markets as different countries/markets will have different subsidies and qualification criteria
- Treatment of interconnector capacities and potential impact on technology de-rating factors or constraint limits in auctions
- Treatment of spare capacity on interconnectors post auction
- Role of secondary trading across interconnectors between different countries
- Performance metrics under stress events, penalties for non-delivery and testing regimes
- More generally, the increased administration burden of a significant increase in participants and rules around the destination of generators output who has multiple CM contracts across different countries markets.

Co-location / hybrid de-rating factor method

The project was split into two phases with only the first being completed in this year's analysis. The second phase of numerical evaluation could be either addressed over the summer or be considered for next year's development cycle.

This project identified the need to consider three types of co-location when there is a connection constraint that doesn't allow full output from all technologies on site.

- Co-located conventional sites
- Co-located wind & conventional sites
- Co-located storage with wind or solar sites

The modelling approach to calculating appropriate de-rating factors was discuss with our academic advisors and it identified several issues that would need to be addressed ahead of any industry consultation:

- Sequential modelling required
- Incremental versus average EFC (risk metric EEU or LOLE)
- Storage duration complications
- Requirement for good connection capacity data from DNOs
- Requirement for detailed growth forecasts for site combinations

- Technology combinations could be based on a multi option matrix of possible combinations for the developer to select from or a pro-rated approach based on the technologies involved
- Issues around testing, administration, pre-qualification etc.

This industry consultation on a proposed method for calculating de-rating factors will be required as per CM Rules ahead of inclusion in prequalification for any future auctions.

Review of Least Worst Regret process for T-1 auction

Following the high level of capacity secured through the 2020/21 T-4 auction, we identified a real risk that many of the sensitivities modelled for the T-1 as part of the LWR process would result in negative requirements. This project investigated the options for how to accommodate this within the LWR process effectively to result in a robust target capacity recommendation that provides value of money for the consumer.

Three options were discussed with the academic consultants as potential ways in which the T-1 LWR analysis could be carried out:

1. Restrict the set of scenarios / sensitivities to those for which the capacity to secure is non-negative
2. Keep the complete set of scenarios / sensitivities but restrict the LWR decision to non-negative values only [equivalent to setting the capacity requirement to zero for all cases with a negative requirement
3. Keep the complete set of scenarios and sensitivities and allow both positive and negative capacity requirement values to be considered in the LWR decision. If the LWR outcome is negative, set the T-1 recommendation to zero.

The project concluded that:

- We recommend including a complete set of scenarios and sensitivities in the T-1 analysis for 2020/21 in the 2019 ECR
- We recommend allowing both positive and negative capacity requirement values to be considered in the LWR decision
- If the outcome of the LWR analysis is a negative target capacity, we recommend adjusting it to zero.

2.6 Modelling Enhancements since Last Report

Section 2.5 describes several development projects carried out in response to BEIS, Ofgem and National Grid ESO's ideas along with the recommendations from the PTE. These developments have not led to any material changes to DDM functionality so any enhancements utilised for the 2019 ECR have related to updating data streams and good housekeeping. However, to support the project on potential renewable technologies participation in the CM, a development of the Unserved Energy Model (UEM) code within the DDM was required which was commissioned in summer 2018.

2.7 Quality Assurance

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

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

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

The PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Internally, the process has governance under Director UK System Operation. National Grid ESO has also worked closely with LCP[18] to check and verify the results obtained as part this analysis to reinforce the robustness of the QA process. For details of the QA undertaken by National Grid ESO, see the Annex A.8.

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

3. Scenarios & Sensitivities

3.1 Overview

National Grid SO has a well-established and extensive consultation process on issues related to demand, generation and security of energy supply. This involves a continuous stakeholder consultation process with industry workshops, a summer seminar and bilateral meetings. The following documents are published annually as part of the process, which we sought feedback on, to improve our process for the following cycle:

- Future Energy Scenarios Stakeholder Engagement | National Grid SO
- Future Energy Scenarios | National Grid SO[19]
- Electricity Ten Year Statement | National Grid ESO
- Gas Ten Year Statement | National Grid

This process results in the development of the Future Energy Scenarios (FES), derived using the latest information available on sources of supply and demand for both electricity and gas. The latest market intelligence is used to create the scenarios; for example, including the Transmission Entry Capacity (TEC) changes announced in March 2019, which are indications to National Grid ESO that power plants have decided to reduce or increase the power that they will supply to the market.

Following extensive analysis and consultation, a new scenario framework was adopted for the 2018 Future Energy Scenarios. This framework remains appropriate and will remain unchanged for FES 2019. This also aligns with feedback from stakeholders for consistency to allow year-on-year comparison of the scenarios.

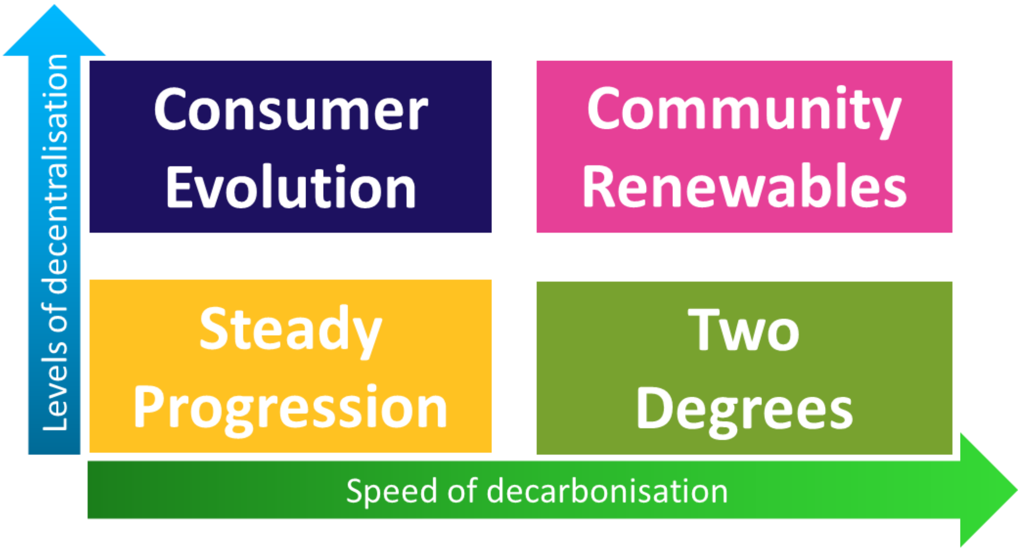
The four scenarios from FES 2018 will therefore be retained for FES 2019 in a 2x2 matrix structured around the axes of 'level of decentralisation' (indicating whereabouts on the energy system solutions are physically located) and 'speed of decarbonisation' (combining policy, economics and consumer attitudes) as illustrated in Figure 9.

Two of the scenarios will meet the 2050 carbon emissions reduction target, with the other two showing slower progress, reflecting current obligations and highlighting the potential challenges.

The scenarios will continue to reflect a mix of technology options, taking account of the rapid changes in the energy industry, markets and consumer behaviour. Security of supply for both gas and electricity will be achieved across the scenarios for FES 2019, as in previous years.

[19] Note that the 2019 document will be published on 11th July 2019

Figure 9: Our scenarios for FES 2019



Given the wide range of applications that the scenarios are already used for, by both National Grid ESO and the wider industry, the logical decision would be to use them for the Capacity Market analysis.

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

3.1.1 Base Case

In addition to the four FES scenarios and to be compliant with our DFA Incentive, we have used a base case known as the 'Five Year Forecast[20]' to 2023/24, against which all the sensitivities will be run. This case follows the same principles and modelling approach as the FES scenarios to give a five-year demand and generation background that is within the four FES scenarios range. Due to the inherent uncertainty across the market beyond 2023/24, the Base Case then follows the FES scenario that is closest in its 2024/25 generation mix, i.e. for 2019 FES, it is closest to Steady Progression scenario.

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

[20] Further detail can be obtained from FES Method document. This will be published along with FES document on 11th July 2019.

Electricity demand

Demand reduction and decarbonisation continues at a slow pace due to economic, political and social focus elsewhere. In the Industrial & Commercial sectors, projections are based on the Oxford Economics best view of economic growth (1.9% for period of 1st April 2018 to 31st March 2024) and fuel prices in December 2018. Electricity demands remain at similar levels to now. Demand in these sectors is heavily influenced by the size of the economy in the UK, which is assumed to have a fairly close trading relationship with the EU. The UK economy is forecast to expand slowly but demand is offset by policy, incentivising slow improvements in energy efficiency. Residential demands are based on the Oxford Economics housing base view, central regression of “Energy Consumption in the UK” data for appliances and energy efficiency, and inclusion of EU halogen lighting policy. Residential light demand falls rapidly with the policy driven phase-out of inefficient bulbs, and all other residential appliance demands fall at slow historic rates.

Transport

Electric cars increase in popularity for consumers as battery prices fall, range increases and more models become available on the market. For commercial road transport, electric, hydrogen and natural gas increase in prevalence as emissions reduction and decarbonisation continues. In the transport sector projections are based upon a bass diffusion model to calculate the proportion of the potential market that adopts the technology at a given time based upon total cost of ownership in relation to the current dominant technology. This is done for Motorbikes, Cars, Light Goods vehicles (vans), Heavy goods vehicles (HGVs) and buses & coaches; cars are further split down into compact, mid-sized and large segments.

Heat

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

Electricity supply

For electricity supply, the 5 Year Forecast represents our best view of the generation that we expect to be operational using the best intelligence and data available to us. This includes generation connected to the transmission and distribution networks, as well as interconnectors and storage. This is based on a combination of market intelligence[21] and economic modelling. In most cases, we would expect generation to deliver in line with capacity market agreements and contracts for difference, although we make some allowance for non-delivery, dependent on market intelligence. The four scenarios then consider some of the uncertainties around this view. This includes things like what happens if some power stations close early or stay open longer than expected, or if new

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

projects are delayed or built ahead of schedule. These assumptions vary across the scenarios in line with the FES Scenario Framework.

Gas supply

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

The 5 Year Forecast provides a base case for use in a number of National Grid ESO processes.

3.2 Scenario Descriptions

Detailed below are the four scenarios for 2019 using the broad themes of energy demand, transport, heat, electricity supply and gas supply.

3.2.1 Community Renewables

This scenario explores how the 2050 decarbonisation target can be achieved in a more decentralised energy landscape.

Energy demand: In this scenario, we assume the highest level of consumer engagement. We have made this assumption as the take up of smaller, decentralised energy solutions such as residential solar is likely to be associated with greater consumer engagement in energy more generally. Consequently, in this scenario, we predict extensive use of smart technology and demand side response to manage peak electricity demand, alongside improvements in appliance efficiency. Natural gas demand could be the lowest in this scenario, due to the higher electrification of heat and an increase in renewable electricity generation.

Transport: Electric vehicles will become the most popular personal vehicle in this scenario, whilst hydrogen may become more widely used for commercial vehicles. Vehicle sharing is also likely to increase, as may the use of autonomous vehicles.

Heat: In both the 2050 compliant scenarios, we assume homes will become substantially more thermal efficient. Alongside this, in Community Renewables, many homes are expected to move to various types of heat pumps and hybrid heat systems, supplemented by green gas and district heating, with some continued use of gas boilers.

Electricity supply: Smaller, decentralised generation technologies that support decarbonisation such as onshore wind and solar are expected to be more prominent in this scenario. This decarbonised world with high levels of renewable generation may also support the development of new sectors, such as hydrogen production by electrolysis. Battery storage is expected to play a key role in providing flexibility, with interconnectors and larger-scale storage also expected to play a role.

Gas supply: In common with all the scenarios, output from the UK Continental Shelf (UKCS) is expected to decrease in Community Renewables. This scenario is likely to have the most green gas and no shale gas production.

3.2.2 Two Degrees

This scenario explores how the 2050 decarbonisation target could be achieved in a more centralised energy landscape.

Energy demand: Given the faster pace of decarbonisation, this scenario is expected to have fairly high consumer engagement, with use of smart technologies and demand side response to manage peak electricity demand. Appliance efficiency continues to improve. In this scenario, gas is used to create hydrogen via steam methane reforming with carbon capture utilisation and storage (CCUS). The hydrogen is then used in domestic heating, commercial transport and industry.

Transport: Electric vehicles could become the most popular personal vehicle in this scenario, whilst hydrogen may become more widely used for commercial vehicles. Vehicle sharing is likely to increase, as does the use of autonomous vehicles. Public transport use is expected to grow most quickly in this scenario.

Heat: In both the 2050 compliant scenarios, we assume homes to become substantially more thermally efficient. Alongside this, in Two Degrees, hydrogen heating could be rolled out in several cities across GB. Hydrogen heating features in this more centralised scenario as the need for hydrogen networks means that this technology is likely to require significant capital injection and national co-ordination. Heat pumps, district heating, green gas, hybrid heat systems and gas boilers also feature.

Electricity supply: Larger, centralised generation technologies that support decarbonisation such as offshore wind, nuclear and CCUS are expected to be more prominent in this scenario. Interconnectors and storage (both larger-scale and smaller batteries) are expected to play a key role in providing flexibility.

Gas supply: As UKCS output is expected to decrease in this scenario, other sources of gas such as Norwegian, other imports and green gas increase to meet demand. There is likely to be no shale gas in this scenario.

3.2.3 Steady Progression

This scenario considers a more centralised pathway that makes progress towards, but does not achieve, the 2050 decarbonisation target.

Energy demand: The two slower decarbonising scenarios are expected to have the lowest level of consumer engagement and slower improvements in appliance efficiency compared to the 2050 compliant scenarios. However, growth of electric vehicles will mean that smart technology is still important in managing peak electricity demand. Gas demand is likely to remain high as gas continues to be used in both heating and electricity generation. Some gas will be used to create hydrogen via steam methane reforming with CCUS.

Transport: In this scenario, electric vehicles are anticipated to become more popular but grow at a slower pace, along with some very limited growth in hydrogen fuel cell use in commercial vehicles.

Heat: Homes could gradually become more thermal efficient in this scenario but slower than in the faster decarbonising scenarios. There is likely to be some limited hydrogen blending in gas networks and, despite this, gas boilers are expected to still be the most widespread form of heating by 2050, although there could be some growth in heat pumps and other decarbonised heat technologies.

Electricity supply: Larger, centralised generation technologies are expected to be more prominent in this scenario. However, the deployment of technologies that support decarbonisation such as offshore wind, nuclear and CCUS is expected to be slower than in the 2050-compliant scenarios. This may place greater reliance on gas, particularly larger combined cycle gas turbines (CCGTs), for both generation and flexibility. Interconnectors and storage are also expected to provide flexibility.

Gas supply: As in the other scenarios, as UKCS output decreases, other sources of gas such as from Norway, Continental Europe and liquefied natural gas (LNG) increase. This scenario has minimal green gas and is likely to have some shale gas production.

3.2.4 Consumer Evolution

This scenario considers a decentralised pathway that makes progress towards, but does not achieve the 2050 decarbonisation target.

Energy demand: The two slower decarbonising scenarios are likely to have the lowest level of consumer engagement and slower improvements in appliance efficiency compared to the 2050 compliant scenarios. However, in the Consumer Evolution world there are expected to be some improvements in building efficiency as well as households and communities taking up local generation schemes.

Transport: In this scenario, electric vehicles could become more popular but grow at a slower pace, along with some very limited growth in hydrogen fuel cell use in commercial vehicles.

Heat: Like in Steady Progression, homes are likely to gradually become more thermal efficient in this scenario but slower than in the 2050 compliant scenarios. There could be some limited electrification of heat, with some homes having electric and hybrid heat pumps.

Electricity supply: Smaller, decentralised generation technologies will be more prominent in this scenario. However, the deployment of technologies that support decarbonisation, such as onshore wind, solar and batteries, is expected to be slower than in the 2050 compliant scenarios. This may place greater reliance on gas, with small-scale peaking plant expected to play an important role in providing flexibility.

Gas supply: As UKCS output is anticipated to decrease in this scenario, other sources of gas such as from Norway, Continental Europe and LNG could increase. There is expected to be little green gas but production of shale gas is likely to be highest in this scenario.

3.3 Demand Forecast until 2023/24

The ‘Five Year Forecast’ covers the period 2019/20 to 2023/24. It supports the DFA incentive, which along with EMR sensitivity analysis and the 4 scenarios is a key part of recommending a capacity to secure. Industrial and commercial demand comprises around half of the peak forecast and is based on current views of energy policy and the latest ‘Oxford Economics’ baseline economic and price forecasts. Residential demand comprises the second half of peak and takes into account energy policy, consumer behaviour and uptake of new technologies such as electric vehicles and heat pumps.

The Base Case peak underlying demand forecast is lower this year than the forecast in 2018. By 2023/24 this year's forecast is 1.7 GW lower; 58.9 GW compared to 60.6 GW. There are four main reasons for this:

- We delivered an innovation project which showed evidence of different electric vehicle charging behaviour, compared to our assumptions last year – with EV owners charging less frequently and at different times (away from system peak). This reduced the forecast by **0.8 GW** for 2023/24.
- The data we receive relating to historical residential demands was revised this year, which led to revised trends from the regression analysis. This reduced the forecast by **0.4 GW** for 2023/24.
- Recent history of annual and peak demands has also shown a change in correlation. This reduced the forecast by **0.3 GW** for 2023/24.
- The EU residential halogen lighting ban is included in the Base Case, whereas in 2018 it was not. At the time of delivering the 2018 forecast it was not clear if the proposed ban would be agreed or not – in the event it was agreed in 2018. This reduced the forecast by **0.2 GW** for 2023/24.

Figure 10 and Table 2 show the peak demands for the Base Case and the FES scenarios over the five-year period. The chart also shows historic peak demands since 2013/14.

Figure 10: Peak Demand - FES Scenarios and Base Case to 2023/24

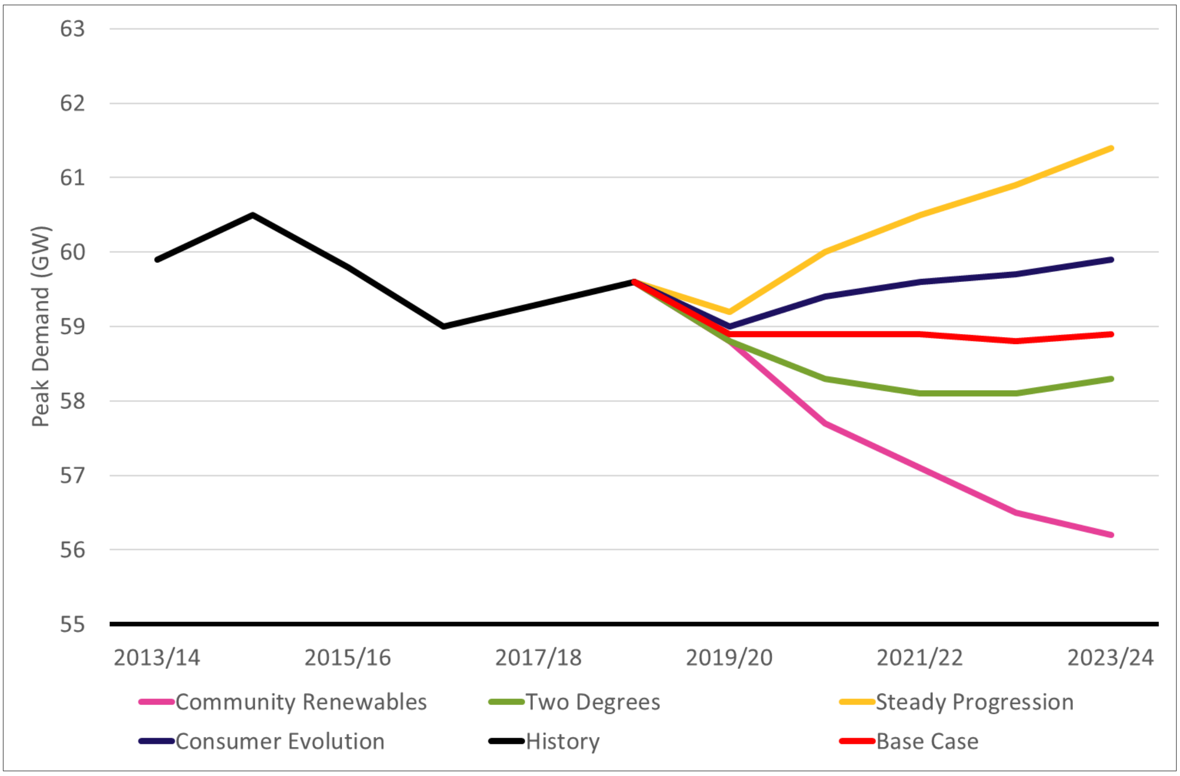


Table 2: Peak Demand to 2023/24

Peak Demand GW	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Base Case	59.6	58.9	58.9	58.9	58.8	58.9
Community Renewables	59.6	58.8	57.7	57.1	56.5	56.2
Two Degrees	59.6	58.8	58.3	58.1	58.1	58.3
Steady Progression	59.6	59.2	60.0	60.5	60.9	61.4
Consumer Evolution	59.6	59.0	59.4	59.6	59.7	59.9

Based on FES18 stakeholder feedback, we have evolved the scenarios and better reflected future possibilities with a wider range of uncertainty for 2019. A key change has been to use a wider set of fuel price scenarios and energy efficiency assumptions. Community Renewables and Two Degrees are similar to last year in that they are more energy efficient than the other scenarios, but they also have high fuel price assumptions. This offsets the effect of higher GDP, faster low carbon transport growth and earlier low carbon heat adoption. Steady Progression and Consumer Evolution are also similar to their 2018 predecessors – with lower energy efficiency but lower fuel prices, resulting in higher demands despite lower GDP and slower technology adoption.

3.4 Demand Forecast 2024/25 onwards

The scenarios have evolved since 2018 in order to better reflect a range of credible demand scenarios. As well as a wider range of fuel prices and general energy efficiencies, we have reviewed all of the FES components including adoption of electrified road transport, low carbon heat and residential thermal insulation. Demand is expected to increase from the mid-2020s due to generation adoption of electrified road transport and electrified, low carbon heat. Key uncertainties are the levels of 'smart' energy use to reduce system peak (particularly from electric vehicle charging and heat storage) and the speed of adoption.

The definition of peak demand used in the modelling is Unrestricted GB National Demand[22], 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.

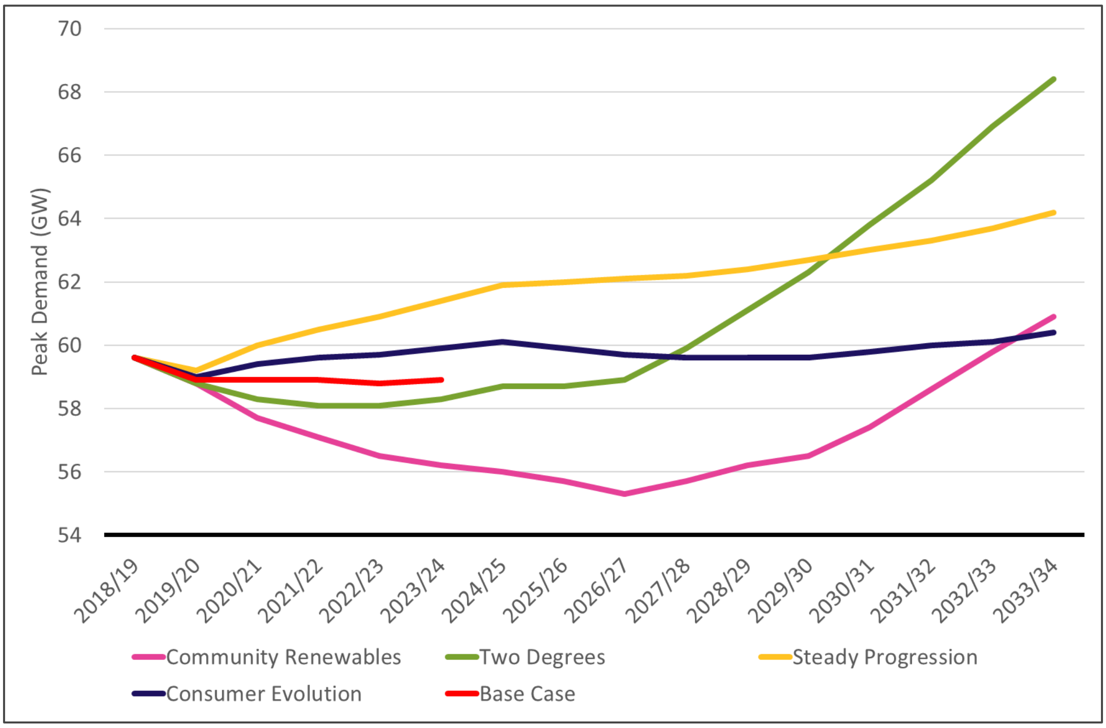
Demand is based on the Average Cold Spell[23] (ACS) peak demand and is consistently applied within the sensitivities based on the Base Case. The only adjustments to ACS peak demand are within the high and low demand sensitivities. All forms of DSR greater than 2 MW are eligible for the Capacity Market. This can include DSR through the use of an aggregation service (including DSR <2 MW). Note that this includes DSR at times of Triad charging periods. Therefore, unrestricted peak demand is modelled, i.e. no DSR or Triad avoidance has been subtracted.

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

[22] National demand is defined in the Grid Code 'Glossary and Definitions' https://www.nationalgrideso.com/codes/grid-code?code-documents=
[23] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

Figure 11 shows the peak demands used in the DDM modelling to 2033/34.

Figure 11: Peak Demand - FES Scenarios and Base Case to 2033/34



3.5 Generation Capacity until 2023/24

Our generation capacity forecast from 2019/20 to 2023/24 is based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years.

The Base Case sits within the uncertainty envelope provided by the 2019 Future Energy Scenarios as shown in Figure 12. Transmission nameplate capacities are shown in Table 3.[24]

[24] Note that this includes all transmission-connected capacity except interconnectors

Figure 12: FES 2019 Transmission connected nameplate capacity to 2023/24

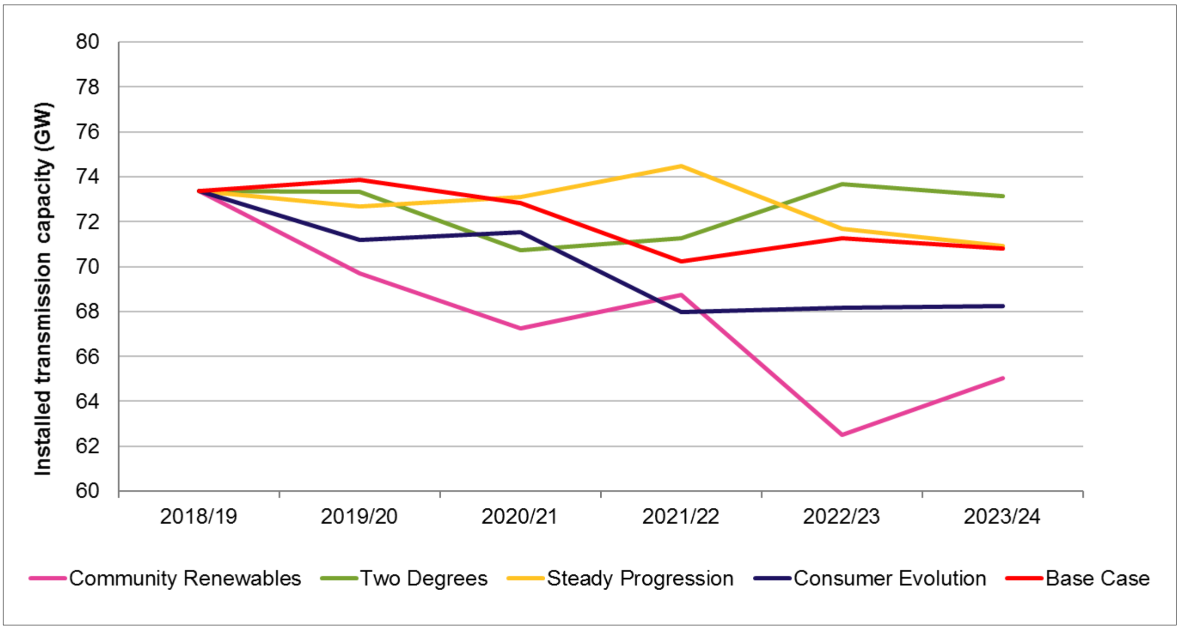


Table 3: Transmission connected nameplate capacity (GW) to 2023/24

Capacity GW	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Base Case	73.4	73.9	72.9	70.2	71.3	70.8
Community Renewables	73.4	69.7	67.2	68.8	62.5	65.0
Two Degrees	73.4	73.3	70.7	71.2	73.7	73.1
Steady Progression	73.4	72.7	73.1	74.5	71.7	70.9
Consumer Evolution	73.4	71.2	71.5	68.0	68.2	68.2

3.6 Generation Capacity 2024/25 onwards

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

Capacity Market eligibility

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

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

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

In addition, any generation capacity that is under a total capacity of 2 MW is assumed not to be eligible for the Capacity Market in this modelling – although any plant under 2 MW not receiving support from the above schemes can enter the auction if combined with other capacity by an aggregator. This latter group is estimated to range from 0.9 GW to 1.0 GW in the period to 2023/24 depending on the FES scenario and year and includes some onsite autogeneration above 2 MW assumed to opt out of the Capacity Market. Note that small scale renewable technologies are assumed to receive FiT support and therefore are excluded from this range.

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

Assumptions

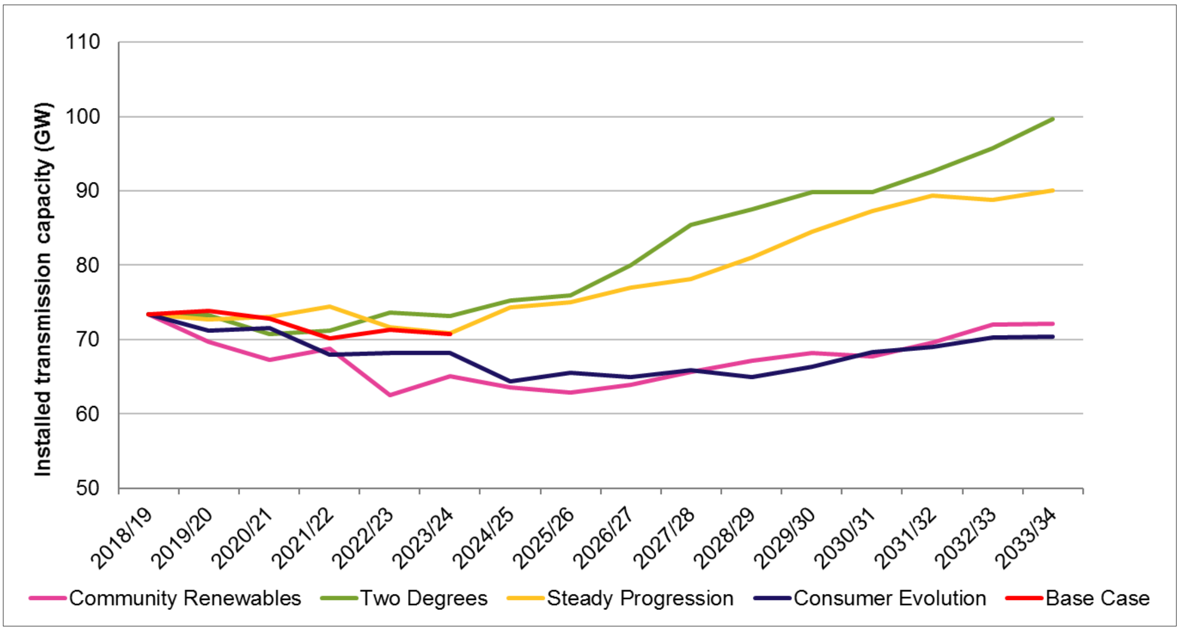
Barring these exceptions based on size and support mechanism, all other forms of generation capacity are eligible for the Capacity Market. For the purposes of our modelling, we assume that:

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

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

The focus of the modelling is to estimate the total eligible de-rated capacity that needs to be secured in order to achieve a reliability standard of 3 hours LOLE or lower. The final mix of generation technologies that make up this total capacity will be decided by the capacity auction and is not predetermined as a result of the modelling. A breakdown of installed capacity for each FES scenario is shown in Figure 13.

Figure 13: FES 2019 transmission connected nameplate capacity to 2033/34



Annex A.4 contains a breakdown of generation that is eligible and not eligible for the CM. Further details of the underlying generation assumptions, including the technology mix, will be available when the FES 2019 document is published on 11th July 2019.

3.7 Distributed Generation

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

The scenarios consider 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[25].

A variety of data sources[26] are used to develop a list of projects for existing generation above 1 MW in size. We are continually seeking to improve the data available, as well as our analysis, in order to have an improved picture of how distributed generation operates over the year. This will help us to improve our understanding of how small-scale plant contributes to demand across the seasons.

The ECR uses overall underlying demand (See Section 3.4). For other purposes, demand on the transmission network can be calculated using the output from distributed resources netted off overall demand. Figure 14 and Table 4 show nameplate capacities (excluding

[25] The de-rating factor for solar is less than 2% for CM auctions
[26] For example, Renewable Energy Planning Database, CM register, DNO long term development statement and others

solar) for distributed generation out to 2023/24. Figure 15 extends the capacities out to 2033/34.

Figure 14: Distributed generation nameplate capacity (excl. solar) to 2023/24

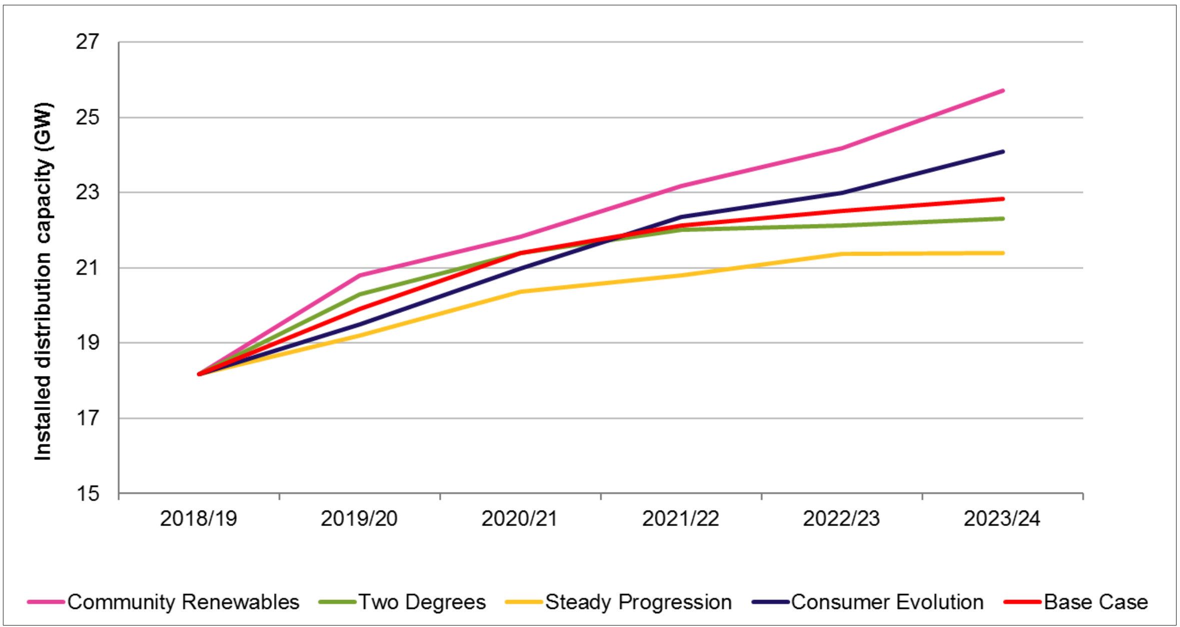
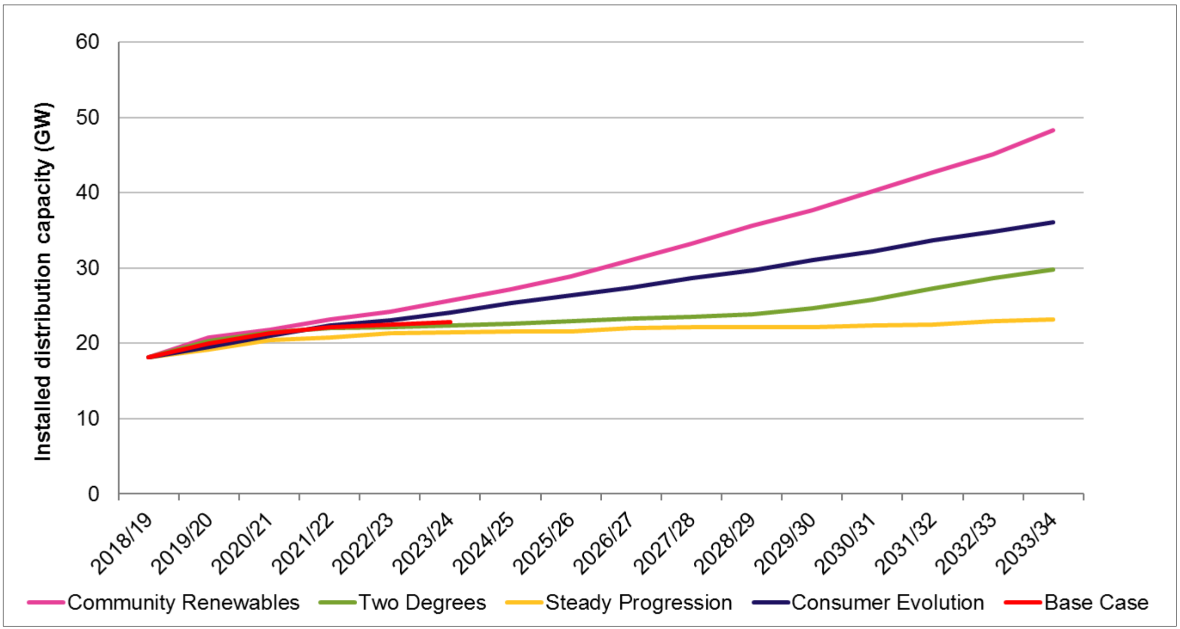


Table 4: Distributed generation nameplate capacity (excluding solar) (GW)[27]

Capacity GW	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Base Case	18.2	19.9	21.4	22.1	22.5	22.8
Community Renewables	18.2	20.8	21.8	23.2	24.2	25.7
Two Degrees	18.2	20.3	21.4	22.0	22.1	22.3
Steady Progression	18.2	19.2	20.4	20.8	21.4	21.4
Consumer Evolution	18.2	19.5	21.0	22.3	23.0	24.1

[27] Includes capacity <1 MW

Figure 15: Distributed Generation (excluding Solar) to 2033/34 (GW)



3.8 Demand Side Response

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

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

Domestic Peak Response

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

Smart Meters: These only have a short-lived behavioural impact by themselves. Their impact is enhanced where they are supported by appropriate marketing and education around energy use. We see this happening more in the greener scenarios. Only in Two Degrees and Community Renewables do we see the government's roll-out plan being delivered on time.

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

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

Industrial and Commercial DSR

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

Figure 16 shows the industrial and commercial DSR for the scenarios to 2033/34, with Table 5 showing projections to 2023/24 and spot years for 2028/29 and 2033/34. There is little change in the overall DSR for the next few years but post 2020 some barriers, such as the complexity of the market place, ease off allowing for a divergence in the scenarios' pathways. For the next ten to fifteen years, in all the scenarios, there is a growth and development in the enabling systems, such information communications technology, which permit DSR to evolve. Thereafter, this growth tails off and so dampens the initial rate of increase.

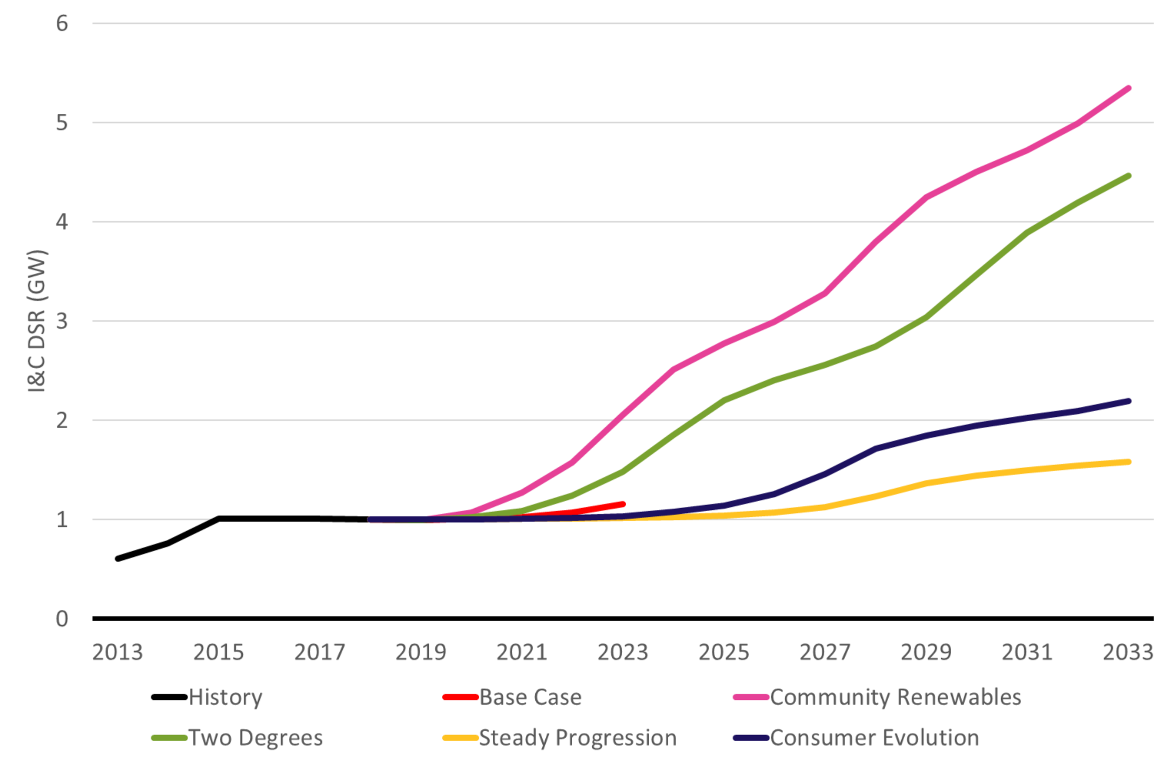
The most significant differentiator between the DSR take-up is decarbonisation. More DSR products enter the market place in the scenarios with more renewable generation: Consumer Renewables and Two Degrees. These products are used by businesses as income generators, for supplying balancing services, or as cost saving by reducing their exposure to more expensive charges.

In the scenarios with lower decarbonisation, there are fewer drivers of DSR and subsequently, fewer DSR products in the market place. The more ambitious scenarios have sharp growth during the 2020s (as shown in the two extra years in Table 5) but initial take-off is still expected to be slow: the range of industrial and commercial DSR over the Base Case and the four FES scenarios in 2023/24 is from 1.0 GW to 2.1 GW, which is wider than assumed in 2018 (1.0 to 1.2 GW). The update is due to a change in modelling method, which better reflects the potential of DSR. The range by 2033/34 is 1.6 GW to 5.3 GW, wider than previously assumed in 2018 (1.4 GW to 2.9 GW).

Table 5: Industrial and Commercial DSR (GW)

GW reductions (I&C)	2019/20	2020/21	2021/22	2022/23	2023/24	2028/29	2033/34
Base Case	1.0	1.0	1.0	1.1	1.2		
Community Renewables	1.0	1.1	1.3	1.6	2.1	4.2	5.3
Two Degrees	1.0	1.0	1.1	1.2	1.5	3.0	4.5
Steady Progression	1.0	1.0	1.0	1.0	1.0	1.4	1.6
Consumer Evolution	1.0	1.0	1.0	1.0	1.0	1.8	2.2

Figure 16: Industrial and Commercial DSR to 2033/34



Power Responsive

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

Since the programme launched in summer 2015, there has been a substantial increase in momentum across the industry in the desire to facilitate the growth of participation of flexible technologies in energy markets. Around 2500 individuals have signed up to receive regular flexibility updates, whilst a community of 1000 individuals has also been established on Linkedin. Informative materials on demand side flexibility opportunities have been published, including a “comprehensive guide to DSR” for energy managers in collaboration with the Major Energy Users Council. There are also regular open forum working groups for both flexibility stakeholders, and industry specific workshops to engage with I&C customers. The recent Power Responsive Summer Reception received over 400 registrations alone.

3.9 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects. We have anonymised the data by showing only the total capacity per year, due to commercial sensitivities. Our analysis assumes continued market harmonisation between the UK and Europe once the UK has left the European Union, for example, the UK continues to participate in the Internal Energy Market or similar future arrangements are developed.

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

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

Table 6 depicts the import capacity levels of interconnection for each scenario. Interconnector capacity is assumed to be higher in scenarios that meet decarbonisation on time. Furthermore, interconnector capacity is assumed to be lower in scenarios with greater levels of decentralisation. As such, the highest electricity interconnector capacity is in Two Degrees and the lowest is in Consumer Evolution. Interconnector capacities in both Community Renewables and Steady Progression fall in between these limits.

Table 6: Import Capacity Levels for Interconnection (GW)

Capacity GW	2020/21	2021/22	2022/23	2023/24	2025/26	2030/31
Base Case	6.8	6.7	7.0	8.4	10.3	14.5
Community Renewables	6.8	6.7	8.4	8.4	11.7	16.5
Two Degrees	6.8	8.1	8.4	10.3	16.5	20.0
Steady Progression	6.8	6.7	8.4	8.4	10.3	14.5
Consumer Evolution	4.8	6.7	7.0	8.4	8.4	11.7

Building on from the work in FES 2017 and 2018, the analysis to assess interconnector flows has been conducted using a pan-European model called BID3 that we have procured from Pöyry[28]. Flows were modelled for each scenario based on the latest available FES 2019 data for Great Britain. The assumptions for other European countries were informed by our European scenarios as described in Section 2.5. These assumptions were based on reports published by other European Transmission System Operators and ENTSO-E.

The CM modelling uses probabilistic distributions from these BID3 simulations as an input to assess the recommended capacity to secure. The CM modelling also uses BID3 to assess the contribution of interconnectors to security of supply to provide a recommendation of the de-rating factor range for each connected market. This is covered

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

in more detail in Section 4.2. Further details on the interconnector flow modelling in FES 2019 will be provided when the document is published on 11th July 2019.

3.10 Sensitivity Descriptions and Justifications

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

While there are many variables that change across the FES scenarios, the sensitivities vary only one at a time. Each of the sensitivities is considered credible as it is evidence based, i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables. The sensitivities cover uncertainty in plant availability, weather, wind, peak demand, over-delivery and non-delivery of contracted capacity.

To provide the reference case to which the sensitivities have been applied, a Base Case has been utilised. Up to 2023/24, the Base Case consists of our ‘best view’ of the demand and generation backgrounds which aligns with the DFA Incentive and aims to reduce the likelihood of over or under securing capacity, thereby minimising the associated costs to consumer. From 2024/25, the Base Case takes the demand and generation mix from the Steady Progression scenario.

The sensitivities are described below. However, there are small differences in the way that these sensitivities were applied to each of the individual year runs: the elements that are different in each year are described in the chapters relating to those years. These sensitivities were discussed with BEIS, PTE and Ofgem and were agreed in May 2019.

3.10.1 Low Wind (at times of cold weather)

The development project discussed in Section 2.5 explained the calculation of the base wind scaling factor of 0.75 to align with the combined storage, wind and solar fleet EFC values. This same development project recommended that the low and high wind sensitivity should be symmetrical around the base case with a scaling factor of 0.5 for the low wind sensitivity.

3.10.2 High Wind (at times of cold weather)

The development project discussed in Section 2.5 explained the calculation of the base wind scaling factor of 0.75 to align with the combined storage, wind and solar fleet EFC values. This same development project recommended that the low and high wind sensitivity should be symmetrical around the base case with a scaling factor of 1.0 for the high wind sensitivity i.e. this sensitivity assumes that wind output is independent of daily peak demand.

3.10.3 High Plant Availabilities

Availability sensitivities have been included for 2020/21 only as they have no material impact on the 2022/23 and 2023/24 analyses as only a small amount of capacity has already been secured for those years. The high and low plant availability sensitivities address the statistical uncertainty associated with determining the mean availabilities of each fuel type. The mean availabilities are determined based on the last 7 years, which is too small a sample size (i.e. just 7 data points) to be confident that the means of these distributions will be statistically representative of what could happen in the future. The plant availability sensitivities are not intended to address concerns of whether the base availability assumptions are too high or too low, and nor are they intended to make predictions as to what levels of plant availability we believe will occur. These are purely statistical sensitivities to address the uncertainty in calculating mean values from a small number of points. To allow for this in the modelling, it assumes for two of the largest contributing generation technologies (nuclear and CCGT) a higher mean availability than the base assumption. This higher availability is also applied to any capacity for these technologies contracted in previous auctions.

For existing nuclear, the availability increases from 81% to 88% and for CCGTs, from 90% to 93% in 2020/21. These higher availabilities are based on one standard deviation above the mean of observed figures from the last seven years. Coal availabilities have not been flexed as coal availabilities have been relatively stable over the last seven years. In addition, other technologies have not been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their high availability levels.

In 2020/21, for example, adjusting availabilities has an impact on the de-rated capacity of previously contracted plant and therefore an impact on the de-rated total required. However, it clearly has a large impact on the name plate capacity total. These adjustments have been applied to the technologies that are both large in aggregate GWs and have shown variance across the sample.

3.10.4 Low Plant Availabilities

Availability sensitivities have been included for 2020/21 only, as they have no material impact on the 2022/23 and 2023/24 analyses. The low plant availability sensitivity assumes for two of the largest contributing generation technologies (nuclear and CCGT) a lower mean availability than the base assumption. For nuclear, the availability reduces from 81% to 74% and for CCGTs, from 90% to 87% in 2020/21. These lower availabilities are based on one standard deviation below the mean of observed figures from the last seven years.

3.10.5 Interconnector Assumptions & Sensitivities

In the 2019 ECR, interconnector capacities are based on the Base Case and FES scenarios. For all the 2020/21, 2022/23 and 2023/24 model runs, the contribution of GB interconnection to security of supply is calculated as part of the probabilistic modelling, hence there is no requirement for separate interconnector sensitivities other than already incorporated within the non-delivery and over-delivery sensitivities.

3.10.6 Cold Weather Winter

The cold weather sensitivity addresses the uncertainty in demand due to cold winter weather conditions. Demand is highly sensitive to weather, and a cold winter will lead to higher demand which increases the risk of loss of load. This sensitivity is included because the modelling uses a relatively short history of demand in the LOLE calculation, which is based on 13 years. This is too small a sample to be confident that the demand distributions will be statistically representative of future weather conditions. For example, the Met Office uses a much longer period of 30 years when calculating average temperatures.

The cold weather sensitivity is based on a recent cold winter and calculates LOLE assuming that the weather that occurred in 2010/11 is repeated. In addition, the weather data is ‘pooled’ rather than being conditional on each winter which is standard practice in many countries. Hence it is statistically sound to run this sensitivity as well as the warm winter sensitivity.

3.10.7 Warm Weather Winter

This warm weather sensitivity is included on the same statistical basis as cold weather and ensures that the treatment of the uncertainty of demand due to weather is unbiased. The warm weather sensitivity is based on a warm winter from within the last 13 years and calculates LOLE assuming that the weather that occurred in 2006/07 is repeated.

3.10.8 High Demand

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

National Grid ESO now has the Demand Forecasting Incentive (DFA) Incentive and an obligation to publish how it plans to improve the demand forecasting process every year. Consequently, the demand sensitivities have been aligned with the ranges used within the incentives rather than historical performance. The DFA Incentive for the T-1 auction has a symmetric range of +/- 2% which forms the basis of the sensitivities in the 2019 ECR. We have not used the T-4 incentive range of +/- 4% as the incentive is weighted towards the

T-1 demand given that there is an opportunity (in the T-1 recommendation) to correct any forecast errors in the T-4 demand.

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

Note that the FES scenarios now have a wider range of demands thus in part is covering this sensitivity but without double counting it.

3.10.9 Low Demand

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

Note that the FES scenarios now have a wider range of demands, thus in part, is covering this sensitivity but without double counting it.

3.10.10 Non-delivery

Previously, non-delivery sensitivities were dominated by the risk around coal closures given their challenging economic situation and environmental legislation. With the decline of the coal fleet the volume of future uncertainty is lower however, new risks have materialised that could add to the non-delivery, e.g. gas plant closures, extended nuclear outages, policy around Ofgem's embedded benefits review, non-delivery risk from unproven DSR failing to materialise (as seen in the TA and EA auctions) and lower than expected imports from interconnectors.

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

Previously we hadn't incorporated directly any nuclear non-delivery risk as plant on extended outages had always returned in time for winter. However, for 2018/19, this wasn't the case when two plants failed to return to service. Consequently, we considered the inclusion of this risk but if we were to assume one plant with de-rated capacity of 0.9 GW failed to deliver this would only add 0.1 GW to the overall non-delivery risk (utilising the Root Sum of Squares approach) and in addition there is a danger of double counting as the nuclear plant availability figure at around 80% allows for more than one plant being unavailable across the winter. Therefore, on balance and from materiality perspective we decided not to include a nuclear non-delivery risk specifically.

Consequently, the non-delivery risks were analysed separately for coal and gas plant, small scale embedded plant (from previous auctions), unproven DSR and interconnectors before applying the Root Sum of Squares approach as agreed with BEIS and the PTE last year. The level of market response was analysed against the aggregated total of non-delivery. This results in a range of risk of 2.4 GW for 2020/21, 2022/23 and 2023/24.

The non-delivery sensitivities deal with uncertainty risks but also assist with the granularity in the LWR calculation. A range of non-delivery sensitivities with incremental steps of 0.4 GW (around the de-rated capacity of a typical coal power station unit) have therefore been modelled up to 2.4 GW. To test the sensitivity of the LWR decision to the maximum non-delivery assumed, an additional non-delivery sensitivity of 2.8 GW was also modelled but not used in our recommendations.

3.10.11 Over-delivery

This sensitivity considers the possibility of over delivery, i.e. stations staying open that do not have CM contracts and interconnectors importing more than their CM contracted de-rated capacities. The former relates to both large scale plant and small scale distributed connected plant. Where the latter relates to interconnectors, assuming capacity is available in the connected markets, delivering higher imports supported by market coupling across physical boundaries within the internal energy market (not-withstanding the risk associated with Brexit). Consequently, we have agreed with BEIS and the PTE to include up to 1.6 GW over delivery for 2020/21, 2022/23 and 2023/24 in 0.4 GW steps. To test the sensitivity of the LWR decision to the maximum over-delivery assumed, an additional over-delivery sensitivity of 2.0 GW was also modelled but not used in our recommendations.

3.10.12 Sensitivities Considered but Rejected

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

Dependence of Generating Units – The DDM implicitly assumes independence in availability of generating units. 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.

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

Black Swan Events – These are defined as events that 'deviate beyond what is normally expected of a situation and are extremely difficult to predict, being typically random and unexpected'[29], 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 winter 2018/19 two nuclear plants failed to return so may be this isn't 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 discussed in last year's PTE report. Given this and the economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with BEIS and the PTE not to include any 'black swan' event sensitivities.

CMU misalignment to TEC – This sensitivity relates to the CMUs (Capacity Market Units) connection capacity being greater than TEC (Transmission Entry Capacity) values for some transmission connected stations so that when the de-rating factors are applied, they result in nearly 100% availabilities for many stations. This clearly puts security of supply at risk, as no plant is 100% available in reality, thus the auction has under secured capacity. However, our modelling mitigates this risk by only using capacities based on TECs, so all our recommendations take account of this anomaly as best it can, with only the T-1 auction potentially under 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 decision tool. We concluded that this would, if included, result in lower probability sensitivities such as combined sensitivities being given equal weightings as sensitivities with only one variable changed which would be inappropriate. Secondly, we considered it as part of the hybrid approach but to change the answer materially required such a low probability sensitivity that it may be considered more like a 'black swan' event and was thus decided not to include.

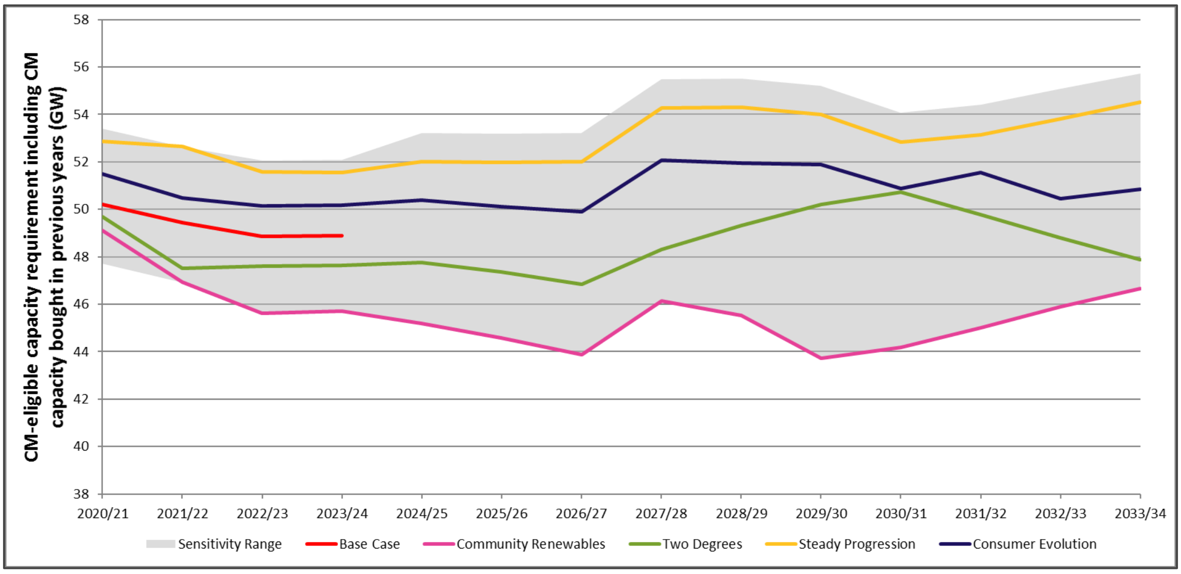
[29] https://www.investopedia.com/terms/b/blackswan.asp

3.11 15 Year Horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2020/21, 2022/23 and 2023/24). It focuses on the total requirement for CM-eligible capacity and does not split each year's requirement into capacity secured in earlier years, T-1 and T-4 auctions. The requirement in 2020/21 and 2021/22 was derived from the 2020/21 model runs (see Chapter 5), the requirement in 2022/23 was derived from the 2022/23 model runs (see Chapter 6) and the capacity requirement from 2023/24 to 2033/34 from the model runs for 2023/24 (see Chapter 7). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 17 shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years.

Figure 17: Total CM-eligible Capacity required in Future Years



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

As can be seen in the chart, the Consumer Evolution and Steady Progression scenarios have a relatively stable capacity requirement over the period whilst the Community Renewables and Two Degrees scenarios show a gradual decline over the first part of the period as the level of de-rated RO/CfD-supported capacity increases by more than any growth in peak demand (plus reserve for largest infeed loss). For the later years, the Community Renewables scenario shows a gradual rise as peak demand increases. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. During the later years of the period, significant amounts of RO-supported wind farms will also come off support further increasing the CM-eligible capacity requirement.

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

The chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2020/21. For 2019/20, we did not model the capacity requirement in each scenario / sensitivity as the T-1 capacity auction for that year will have happened by the time this document is published. The forthcoming 2019/20 Winter Outlook Report[30] will include a view of electricity security of supply for the coming winter.

[30] https://www.nationalgrideso.com/insights/winter-outlook

4. De-rating Factors for CM Auctions

4.1 Conventional and Renewable Plants and Storage

Conventional plant de-rating factors, based on the station availabilities, are updated annually (see Annex A.4.4). Storage de-rating factors, which are also updated annually, are based on the methodology and assumptions outlined in our industry consultation in 2017 (see Annex A.6). Renewable de-rating factors are based on the methodology[31] that was consulted with the industry earlier this year in February 2019. Proposed de-rating factors for 2020/21 (T-1), 2022/23 (T-3) and 2023/24 (T-4) by technology class are depicted in Table 7 for conventional technologies, Table 8 for storage and Table 9 for intermittent renewable technologies. Last year's de-rating factors, which were used for the 2018 Capacity Market Auctions[32], are included for conventional plants and storage.

Table 7: De-rating Factors for Conventional Technologies

<table>
<tr><th>Technology Class</th><th>Plant Types Included</th><th colspan="2">2018 De-rating Factors</th><th colspan="2">2019 De-rating Factors</th></tr>
<tr><td>Oil-fired steam generators</td><td>Conventional steam generators using fuel oil</td><td colspan="2">89.13%</td><td colspan="2">91.26%</td></tr>
<tr><td>Open Cycle Gas Turbine (OCGT)</td><td>Gas turbines running in open cycle fired mode</td><td colspan="2">95.14%</td><td colspan="2">94.98%</td></tr>
<tr><td>Reciprocating engines (non-autogen)</td><td>Reciprocating engines not used for autogeneration</td><td colspan="2">95.14%</td><td colspan="2">94.98%</td></tr>
<tr><td>Nuclear</td><td>Nuclear plants generating electricity</td><td colspan="2">84.20%</td><td colspan="2">81.22%</td></tr>
<tr><td>Hydro
(excl. tidal / waves)</td><td>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</td><td colspan="2">90.09%</td><td colspan="2">89.65%</td></tr>
<tr><td>CCGT</td><td>Combined Cycle Gas Turbine plants</td><td>T-1
89.05%</td><td>T-4
90.00%</td><td>T-1
90.00%</td><td>T-3/T-4
90.00%</td></tr>
<tr><td>CHP and autogen (de-rating factors provided by BEIS)</td><td>Combined Heat and Power plants (large and small-scale)
Autogeneration – including reciprocating engines burning oil or gas</td><td colspan="2">90.00%</td><td colspan="2">90.00%</td></tr>
<tr><td>Coal</td><td>Conventional steam generators using coal</td><td colspan="2">86.56%</td><td colspan="2">85.81%</td></tr>
<tr><td>Biomass</td><td>Conventional steam generators using biomass</td><td colspan="2">86.56%</td><td colspan="2">85.81%</td></tr>
<tr><td>Energy from Waste</td><td>Generation of energy from waste, including generation of energy from:
a) conventional steam generators using waste;
b) anaerobic digestion;
c) pyrolysis; and
d) gasification.</td><td colspan="2">86.56%</td><td colspan="2">85.81%</td></tr>
<tr><td>DSR[33]</td><td></td><td colspan="2">84.28%</td><td colspan="2">86.14%</td></tr>
</table>

[31] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf
[32] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/197/Auction%20Guidelines%202018%20v2.0.pdf
[33] Details of the DSR De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf

Table 8 shows the de-rating factors for storage sites with various durations (in hours). Plant types included are: “Conversion of imported electricity into a form of energy which can be stored and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies.”

Table 8: De-rating Factors for Storage Technologies

<table>
<tr><th>Duration (hours)</th><th>ECR 2018 T-1 2019/20</th><th>ECR 2018 T-4 2022/23</th><th>ECR 2019 T-1 2020/21</th><th>ECR 2019 T-3 2022/23</th><th>ECR 2019 T-4 2023/24</th></tr>
<tr><td>0.5</td><td>17.50 %</td><td>14.91 %</td><td>12.26 %</td><td>10.59 %</td><td>10.21 %</td></tr>
<tr><td>1.0</td><td>34.21 %</td><td>29.40 %</td><td>24.70 %</td><td>21.36 %</td><td>20.43 %</td></tr>
<tr><td>1.5</td><td>50.00 %</td><td>43.57 %</td><td>36.96 %</td><td>31.94 %</td><td>30.83 %</td></tr>
<tr><td>2.0</td><td>62.80 %</td><td>56.68 %</td><td>48.66 %</td><td>42.53 %</td><td>41.04 %</td></tr>
<tr><td>2.5</td><td>71.96 %</td><td>66.82 %</td><td>58.68 %</td><td>52.18 %</td><td>50.51 %</td></tr>
<tr><td>3.0</td><td>78.09 %</td><td>73.76 %</td><td>65.93 %</td><td>59.43 %</td><td>57.94 %</td></tr>
<tr><td>3.5</td><td>81.57 %</td><td>77.78 %</td><td>70.38 %</td><td>64.07 %</td><td>62.77 %</td></tr>
<tr><td>4.0</td><td rowspan="4">95.52 %</td><td>80.00 %</td><td>72.98 %</td><td>67.04 %</td><td>65.93 %</td></tr>
<tr><td>4.5</td><td rowspan="3">95.52 %</td><td>75.03 %</td><td>69.27 %</td><td>68.16 %</td></tr>
<tr><td>5.0</td><td rowspan="2">95.08 %</td><td>71.13 %</td><td>70.20 %</td></tr>
<tr><td>5.5+</td><td>95.08 %</td><td>95.08 %</td></tr>
</table>

The Government has recently made changes to allow wind and solar farms (which are not receiving support under low carbon support schemes, including the RO or CFD) to participate in the Capacity Market. Table 9 presents proposed wind and solar de-rating factors in light of that decision being implemented.

Table 9: De-rating Factors for Intermittent Renewable Technologies

Technology Class	ECR 2019 T-1 2020/21	ECR 2019 T-3 2022/23	ECR 2019 T-4 2023/24
Onshore Wind	8.98%	8.20%	7.42%
Offshore Wind	14.45%	12.30%	10.55%
Solar PV	2.34%	3.13%	3.22%

4.2 Interconnectors

Interconnectors will be eligible to participate in the 2020/21 T-1, the proposed 2022/23 T-3 and the 2023/24 T-4 auctions except where they already have a Capacity Market contract. The future of potential flows through interconnectors is very complex and, consequently, there is no single answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid ESO, in agreement with BEIS and the PTE, has considered in determining an appropriate country's de-rating factor range for the Secretary of State to then decide the factors to apply to individual interconnectors.

4.2.1 Methodology

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

National Grid ESO has a pan-European market modelling team which uses the BID3[34] program to model flows between Great Britain and connected countries for each scenario. BID3 is a dispatch model based on short-run marginal costs. It simulates the hourly demand and generation that would be expected across Europe at historical weather conditions. The weather data is for the same historical hour for all countries to ensure correlations in weather between countries are reflected in the results. BID3 then allocates flows between countries using linear programming to optimise the cost of generation to meet demand across all modelled countries. This year, scenarios were developed for Belgium, France, Germany, Ireland, the Netherlands, Denmark, Norway, Sweden, Poland, Italy and Spain based on scenarios developed by their respective Transmission System Operators and/or ENTSO-E's Ten Year Network Development Plan.

Strategic reserves were not included in the generation capacity because there is very little information and it can change at short notice. Where information is available, strategic reserves are only available outside the market. The exact details vary between countries and it is unclear whether they could be used for exports. For example, Belgium would only release strategic reserves when the market cannot deliver so it is a post market loss of load mitigation action rather than an integral part of the energy market.

Flows were modelled for each scenario based on FES 2019 demand and generation data and FES 2019 electricity interconnector capacities for GB combined with the best matching scenario for each connected country and a single scenario for the remaining European countries. A 30-year demand history correlated between countries, and with wind generation, ensures that the results include a number of periods with extreme weather across Europe, giving greater confidence in the ability of interconnectors to import when required.

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

Lower demand forecasts, early build of new capacity and delayed closure of existing capacity has resulted in healthy margins in the early years of the Future Energy Scenarios, and a lack of stress periods from which to calculate interconnector flows. Without stress periods, GB prices remain low, so there is no driver in the model to attract imports to the UK. The flows would not indicate the potential for imports if they were required. Therefore, for interconnector de-rating modelling only, the GB demand forecasts were increased to a level that gives the number of stress periods that would be expected if the LOLE was around 3 hours. Only the GB demand forecast were adjusted and not the rest of Europe.

The 90 hours with the biggest deficit of GB demand minus GB generation were selected to represent times when imports were required for 3-hour LOLE security. The average flow as a percentage of capacity was calculated for each connected country and FES scenario. As a check on the robustness of the results to the number of hours chosen, a second set of results was calculated for the 30 hours with the biggest deficit. Table 10 lists the simulations.

The modelled range is the highest to the lowest of all the scenario runs from the results of the 90 hours with the lowest GB margins representing an LOLE of 3 hours.

Table 10: Pan-European modelling runs

Scenarios	Graph name	Description
Average of FES scenarios	Average	Average of de-rating factors for BC, CR, TD, SP & CE
Base Case	BC	2019 Future Energy Scenarios - Base Case
Community Renewables	CR	2019 Future Energy Scenarios - Community Renewables
Two Degrees	TD	2019 Future Energy Scenarios - Two Degrees
Steady Progression	SP	2019 Future Energy Scenarios - Steady Progression
Consumer Evolution	CE	2019 Future Energy Scenarios - Consumer Evolution

4.2.2 BID3 Pan-European Model Results

The imports as a percentage of interconnector capacity, from all the pan-European simulations, are shown in for Table 11 for 2020/21, Table 12 for 2022/23 and Table 13 for 2023/24. Where there are blanks in these tables, that country is not connected to Great Britain in that scenario and delivery year. Norway is delayed in the Consumer Evolution scenario for 2022/23. Denmark only appears in the Two Degrees scenario in 2023/24.

The FES results use FES forecasts for Great Britain and the closest scenario for the rest of Europe. GB demands were increased to ensure that the number of stress periods were in the range to be expected when LOLE is around 3 hours. To illustrate the stability of the results to the number of stress periods the percentage imports from the 30 hours with the biggest deficit in GB generation is also shown.

The interconnectors with Ireland and the Netherlands all have capacity market contracts for 2020/21 so simulation results are not shown for these two countries.

Table 11: Simulation results: 2020/21 imports as percentage of interconnector capacity

	GB demand uplift 90 hours						30 hours					
Country	Average	BC	CR	TD	SP	CE	Average	BC	CR	TD	SP	CE
France	94	94	88	96	93	99	91	93	82	94	89	97
Belgium	84	81	75	87	81	98	82	78	69	89	79	96

Table 12: Simulation results: 2022/23 imports as percentage of interconnector capacity

	GB demand uplift 90 hours						30 hours					
Country	Average	BC	CR	TD	SP	CE	Average	BC	CR	TD	SP	CE
Ireland	38	30	39	40	36	44	57	52	61	66	53	56
France	76	78	66	76	81	81	66	67	53	65	71	73
Belgium	59	58	52	58	62	65	44	38	35	39	49	60
Netherlands	51	51	44	50	55	54	36	32	28	27	45	46
Norway	97	99	93	97	96		97	100	96	98	94	

Table 13: Simulation results: 2023/24 imports as percentage of interconnector capacity

	GB demand uplift 90 hours						30 hours					
Country	Average	BC	CR	TD	SP	CE	Average	BC	CR	TD	SP	CE
Ireland	29	24	32	32	32	26	45	39	49	42	52	41
France	70	70	57	74	79	68	57	55	39	69	66	56
Belgium	47	46	39	54	56	38	34	26	19	47	51	27
Netherlands	37	38	30	43	44	30	21	18	9	30	35	14
Norway	97	99	95	98	96	96	98	100	100	100	96	95
Denmark	35			35			17			17		

4.2.3 Country de-ratings

The results for each scenario averages are shown in Figure 19 to Figure 31 and Table 14 to Table 26. **The modelled de-rating factor ranges do not include an allowance for technical de-rating.**

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

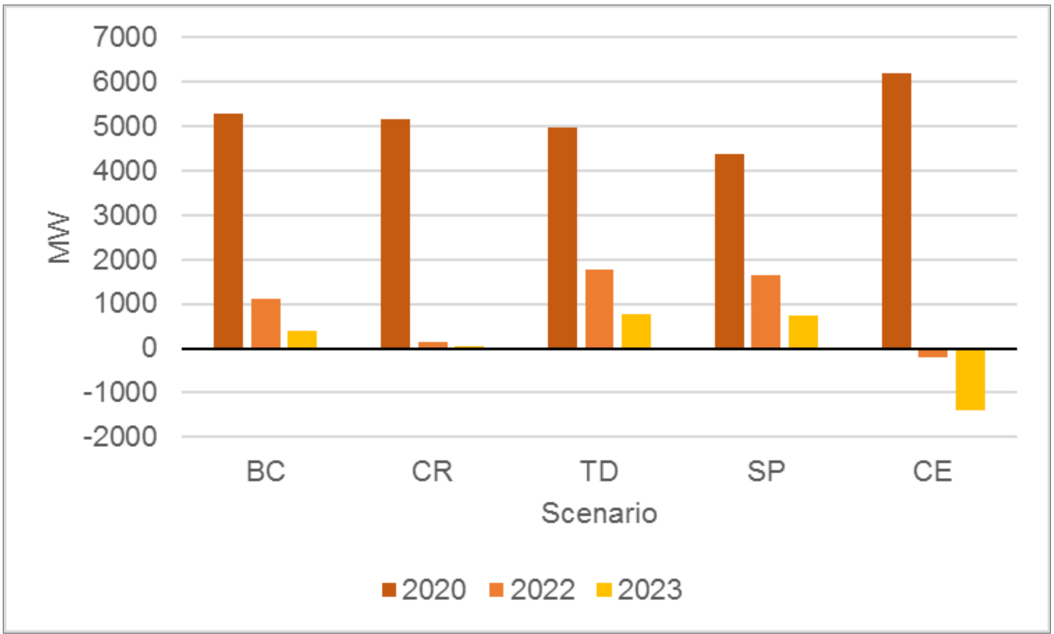
The FES scenarios for 2020/21 have high margins for GB. This is a combination of new generation, with CM contracts in later years, being completed early and some unsuccessful generation without CM contracts staying online to compete for capacity payments in later years. This means that in all scenarios, there are very few hours that meet the low margin criteria for calculating de-rating factors. Therefore, for interconnector de-rating modelling only, the GB demand forecasts have been increased to narrow margins in Great Britain and produce the number of stress periods that would be expected if the LOLE was around 3.

Capability Factor

It has been suggested that the spare capacity in the connected country should be used to calculate interconnector de-rating factors. New for this year, a capability factor has been calculated which represents the potential percentage imports from the surplus generation in the connected country. It is calculated from the lower of the spare capacity in the connected country and the capacity of the interconnector. This capability factor is sometimes lower than the de-rating factor indicating that imports come from further afield than the connected country. It can also be higher than the de-rating factor indicating competition for the spare capacity from other countries or prices for that capacity are not competitive even in a stressed situation. If there is less generation than demand in the connected country, then the capability factor for that hour is set to zero and not the deficit in generation. This is equivalent to assuming the shortfall is not made up by exports from Great Britain.

European margins are falling over the next few years. This along with increased interconnector capacity has a downward pressure on interconnector de-rating factors. The electricity networks of France, Belgium, the Netherlands and Germany are all highly interconnected. Figure 18 shows the total surplus generation for these countries averaged over the 90 hours used to calculate the interconnector de-rating factors.

Figure 18: Surplus generation for France, Belgium, the Netherlands and Germany



Ireland:

Both EWIC and Moyle interconnectors already have capacity market contracts for the 2020/21 delivery year from the 2016 T-4 auction so de-rating factors are not required. The auction de-rating factor was 26% for each interconnector. The modelled ranges for Ireland are 30% to 44% for 2022/23 and 24% to 32% for 2023/24. These ranges assume no outages or network constraints. BEIS will make an allowance for outages and constraints in their de-rating factors for each interconnector. Ireland is a single energy market economically but currently there are limited physical links between the north and south. This is expected to be rectified with an additional North/South link, planned to be commissioned in 2023. Ireland was modelled as a single price area assuming no restrictions on flows within the all-island system. There will be no restrictions on Moyle imports to Great Britain for 2022/23 and 2023/24.

Recently Ireland has shown strong growth in electricity demand, which Eirgrid is forecasting to continue in its 2018 All-Island Generation Capacity Statement[35]. Also, there will be downward pressure on generation as the Irish capacity market currently targets 8 hours LOLE through capacity market auctions.

The capability figures are higher than de-rating factors because the cost of old thermal generation is not competitive enough to generate except in the most extreme events. This discrepancy reduces in the later years due to the most uneconomic plants closing.

Figure 19: Provisional Irish interconnector de-rating factors 2022/23

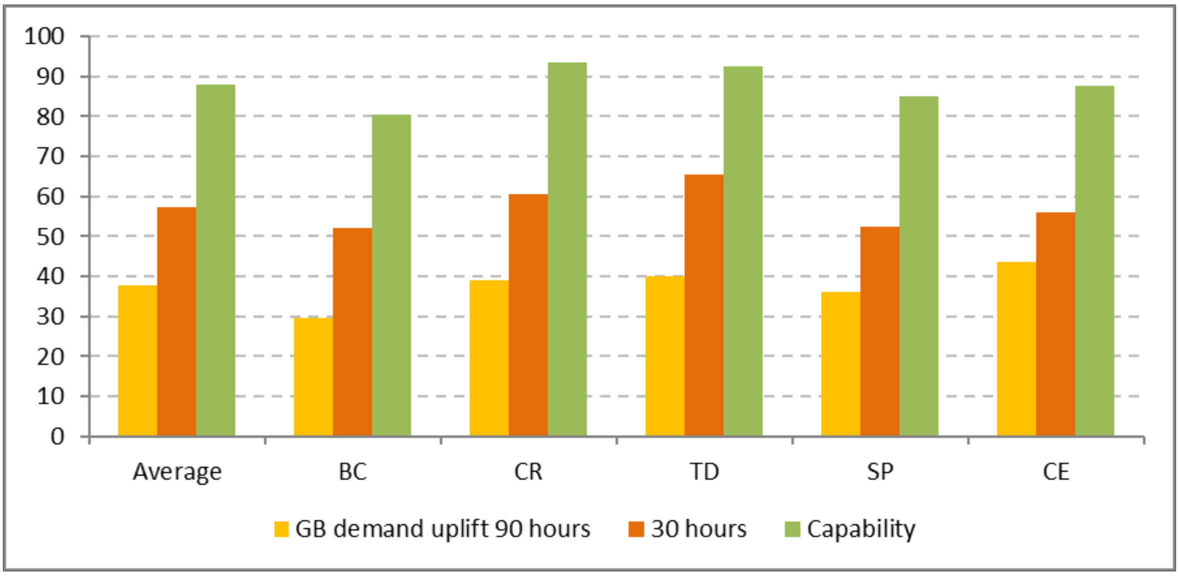


Table 14: Provisional Irish interconnector de-rating factors 2022/23

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	38	30	39	40	36	44
30 hours	57	52	61	66	53	56
Capability	88	80	94	93	85	88

[35] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf

Figure 20: Irish interconnector de-rating factors 2023/24

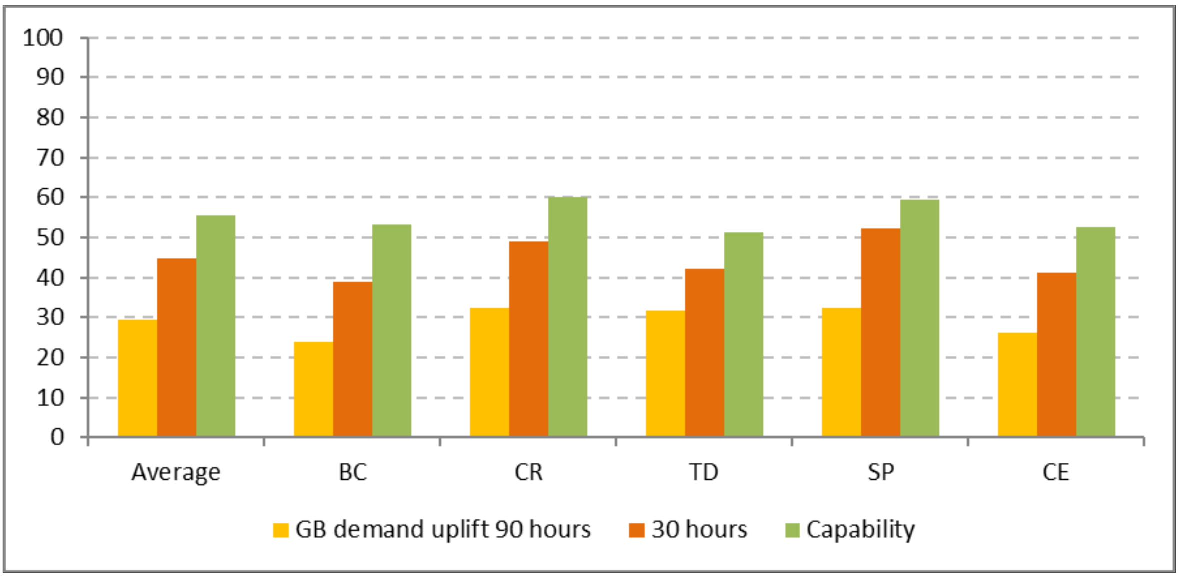


Table 15: Irish interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	29	24	32	32	32	26
30 hours	45	39	49	42	52	41
Capability	55	53	60	51	59	52

France:

The modelled ranges for France are 88% to 99% for 2020/21, 66% to 81% for 2022/23 and 57% to 79% for 2023/24. IFA has a contract for 2020/21 for the 2016 T-4 auction at a de-rating of 60%. The French generation margin is generally positive, although French demand is very weather sensitive, so very cold weather results in demand exceeding domestic generation. As the interconnector capacity with France grows and nuclear capacity is curtailed, we may see de-rating factors falling in the future.

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

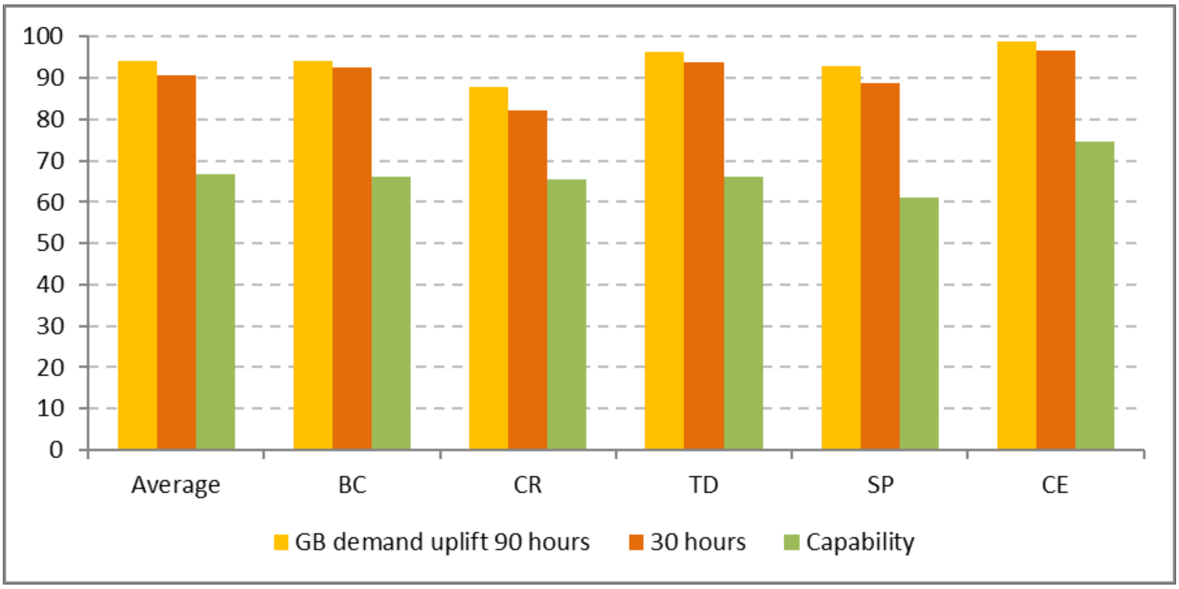


Table 16: French interconnector de-rating factors 2020/21

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	94	94	88	96	93	99
30 hours	91	93	93	94	89	97
Capability	67	66	66	66	61	74

Figure 22: Provisional French interconnector de-rating factors 2022/23

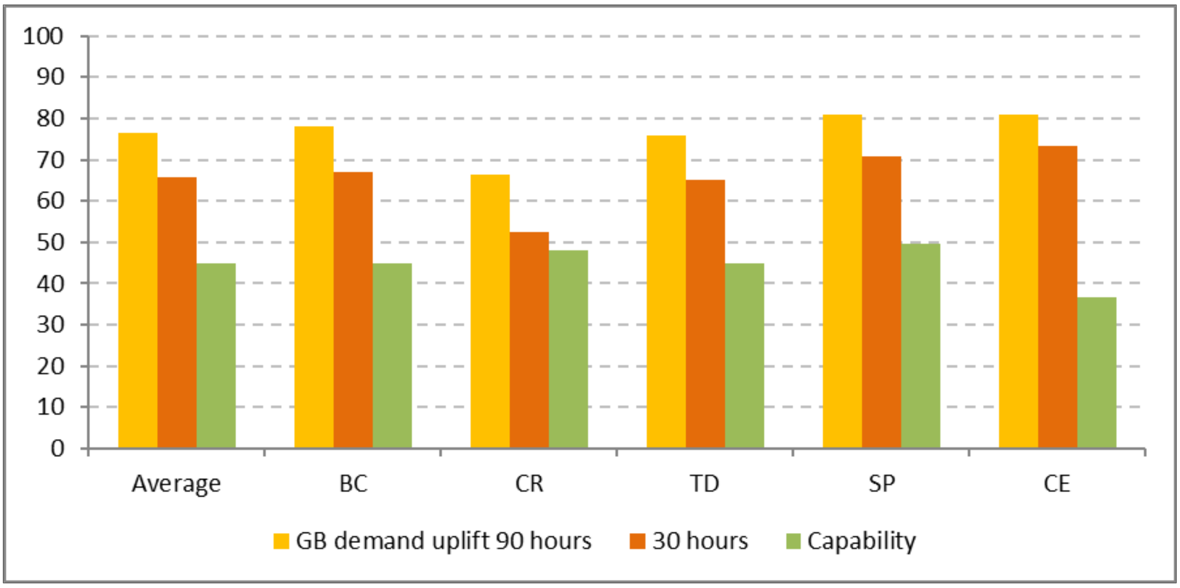


Table 17: Provisional French interconnector de-rating factors 2022/23

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	76	78	66	76	81	81
30 hours	66	67	53	65	71	73
Capability	45	45	48	45	50	37

Figure 23: French interconnector de-rating factors 2023/24

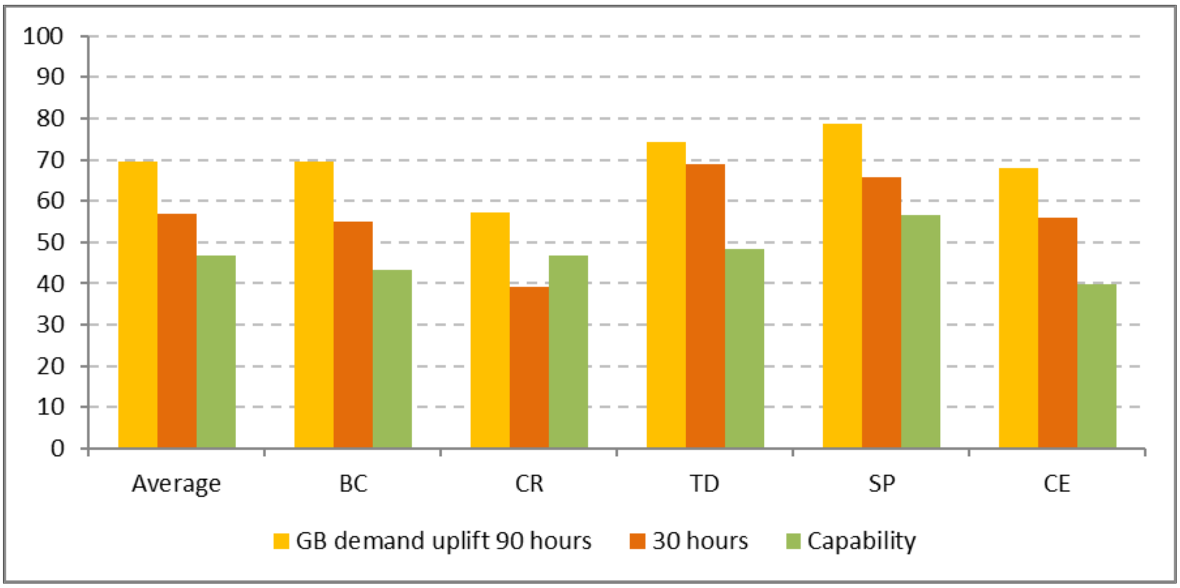


Table 18: French interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	70	70	57	74	79	68
30 hours	57	55	39	69	66	56
Capability	47	43	47	48	57	40

Belgium:

The modelled ranges for Belgium are 75% to 98% for 2020/21. The range drops significantly for 2022/23 to 52% to 65% and even further for 2023/24 to 38% to 56%. For all 3 auction years, Belgium has very little surplus generation at times when Great Britain requires imports. These imports are therefore surplus generation from other countries transported via Belgium. Belgium plans to phase out nuclear power by 2025. This is in progress for 2022/23 with reduced nuclear capacity compared to 2019/20. The drop in de-rating factors is due to the reduction in European margins driven partly by the phase out of German nuclear generation and partly by generation removed from the market as strategic reserve.

Figure 24: Belgium interconnector de-rating factors 2020/21

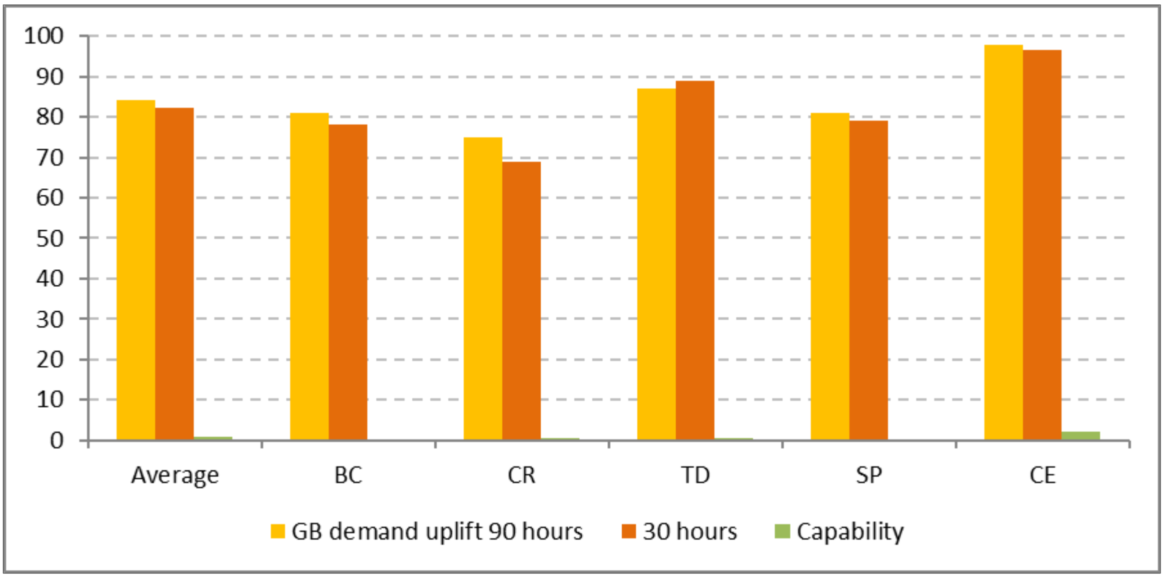


Table 19: Belgium interconnector de-rating factors 2020/21

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	84	81	75	87	81	98
30 hours	82	78	69	89	79	96
Capability	1	0	1	1	0	2

Figure 25: Provisional Belgium interconnector de-rating factors 2022/23

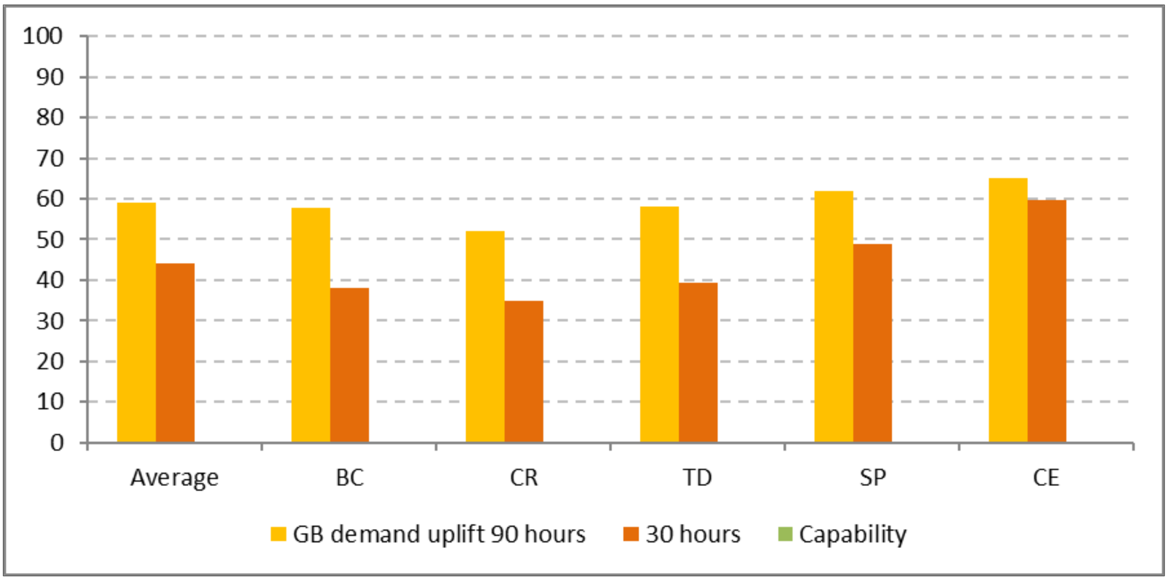


Table 20: Provisional Belgium interconnector de-rating factors 2022/23

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	59	58	52	58	62	65
30 hours	44	38	35	39	49	60
Capability	0	0	0	0	0	0

Figure 26: Belgium interconnector de-rating factors 2023/24

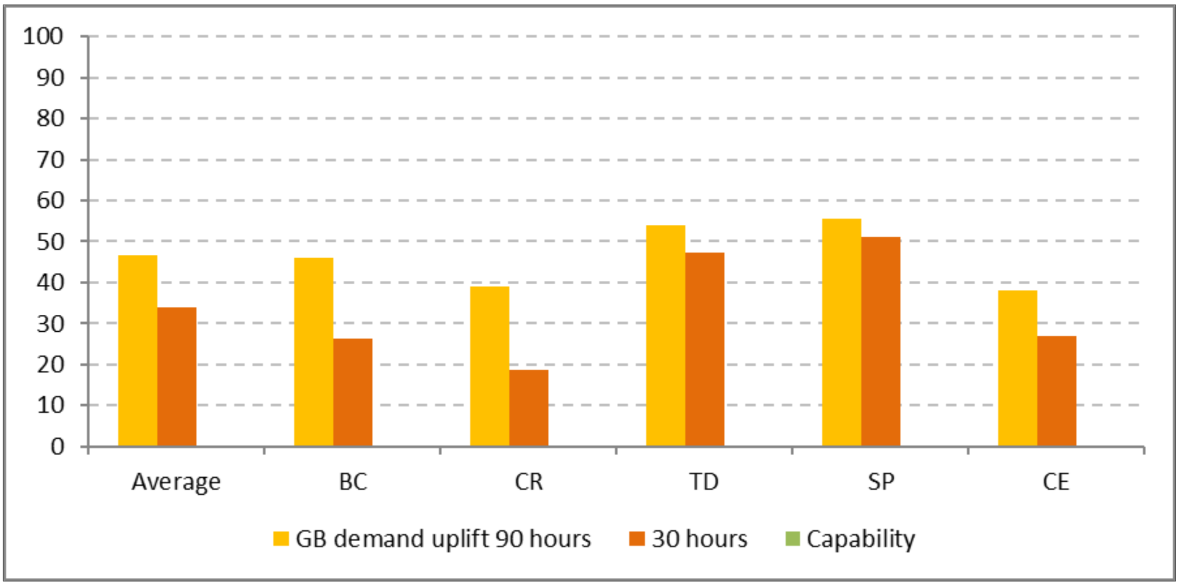


Table 21: Belgium interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	47	46	39	54	56	38
30 hours	34	26	19	47	51	27
Capability	0	0	0	0	0	0

Netherlands:

The Netherlands interconnector already has a capacity market contract for 2020/21 from the 2016 T-4 auction, at a de-rating of 74% on a nameplate capacity of 1200 MW, and there are no further interconnectors to Netherlands planned for this year. Therefore, modelled ranges are only required for 2022/23 and 2023/24. The modelled range for 2022/23 is 44% to 55% reducing to 30% to 44% in 2023/24. Similarly to Belgium, the reduction in de-rating factors is due to the reduction in margins in surrounding countries as there is very little surplus generation in the Netherlands. Mothballing of CCGTs and reduced transit flows from Germany due to government policy to close all nuclear plants by 2022 are two of the reasons for this reduction.

In most countries, the TEC, CMU (Capacity Market Unit) and firm import capacities are the same. This is not the case with Netherlands. The modelling assumed a firm import capacity of 1000 MW and the de-rating factor range is based on this capacity. The maximum historical imports have been 1200 MW although this can only be sustained for a very short time. In the T-4 auction for 2021/22, the CMU capacity was 1320 MW. BEIS will consider whether it is appropriate to adjust the de-rating factors for differences in capacities as well as technical availability.

Figure 27: Provisional Netherlands interconnector de-rating factors 2022/23

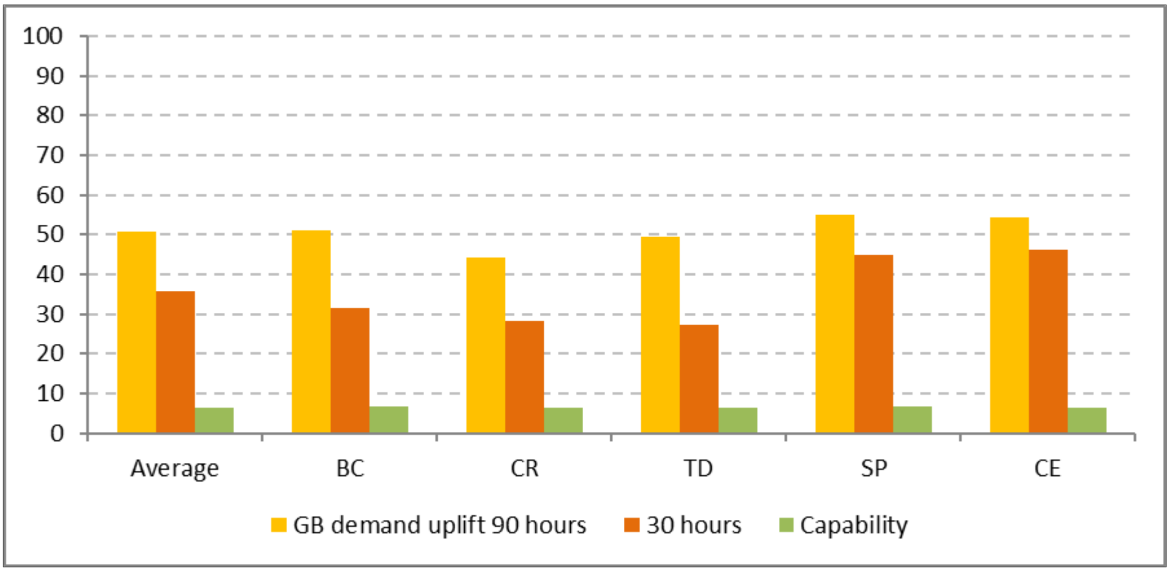


Table 22: Provisional Netherlands interconnector de-rating factors 2022/23

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	51	51	44	50	55	54
30 hours	36	32	28	27	45	46
Capability	7	7	6	6	7	6

Figure 28: Netherlands interconnector de-rating factors 2023/24

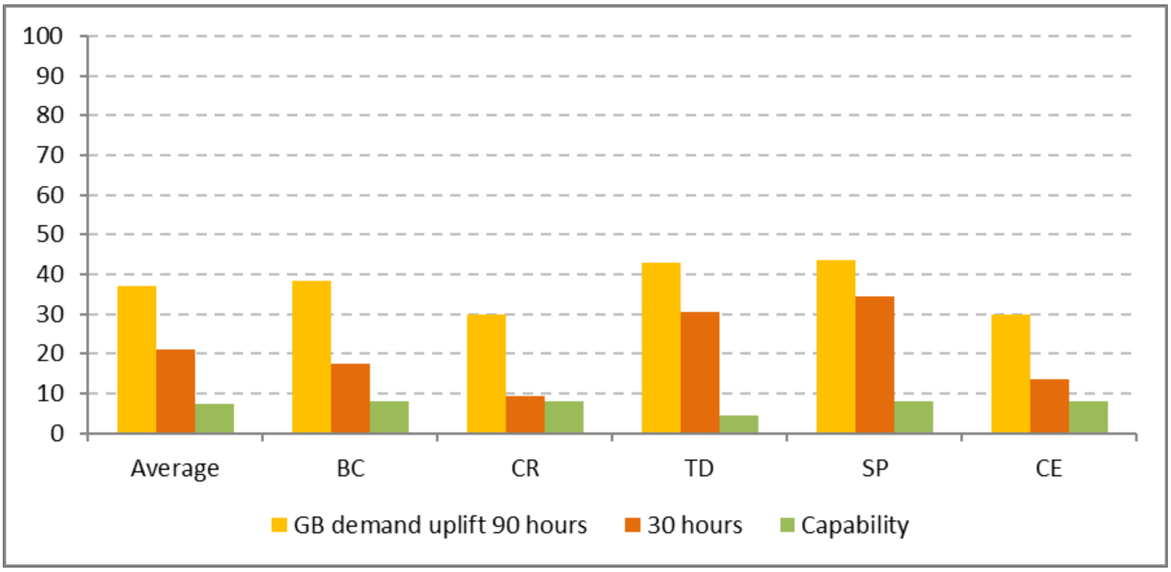


Table 23: Netherlands interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	37	38	30	43	44	30
30 hours	21	18	9	30	35	14
Capability	7	8	8	5	8	8

Norway:

Interconnectors with Norway appear in all scenarios for 2022/23 except Consumer Evolution. The modelled de-rating factors are high across all scenarios giving a range of 93% to 99% for 2022/23 and 95% to 99% for 2023/24.

Figure 29: Provisional Norway interconnector de-rating factors 2022/23

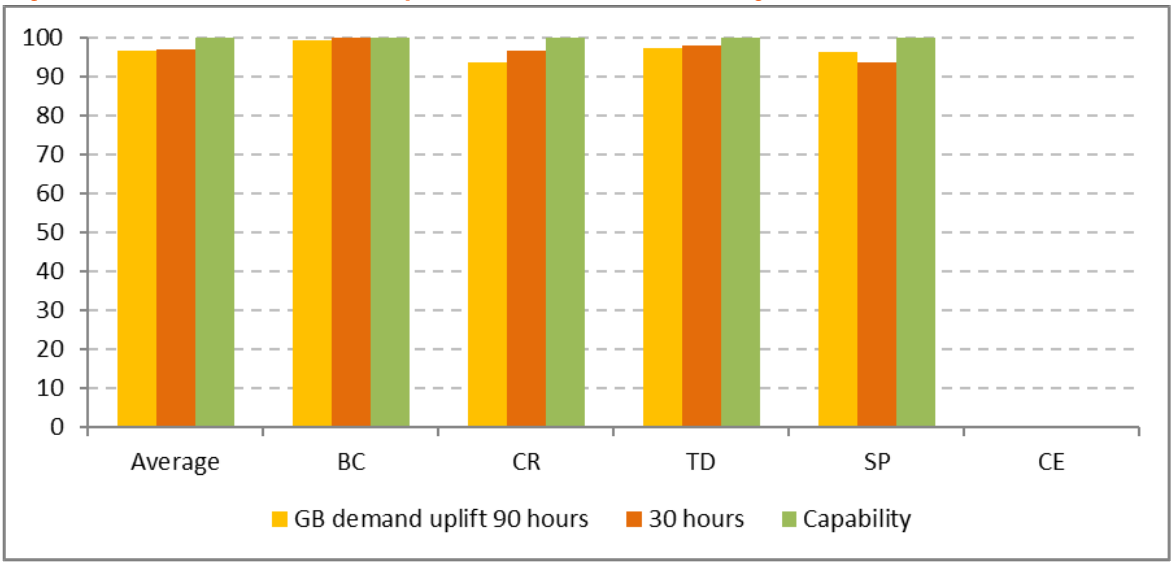


Table 24: Provisional Norway interconnector de-rating factors 2022/23

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	97	99	93	97	96	0
30 hours	97	100	96	98	94	0
Capability	100	100	100	100	100	0

Figure 30: Norway interconnector de-rating factors 2023/24

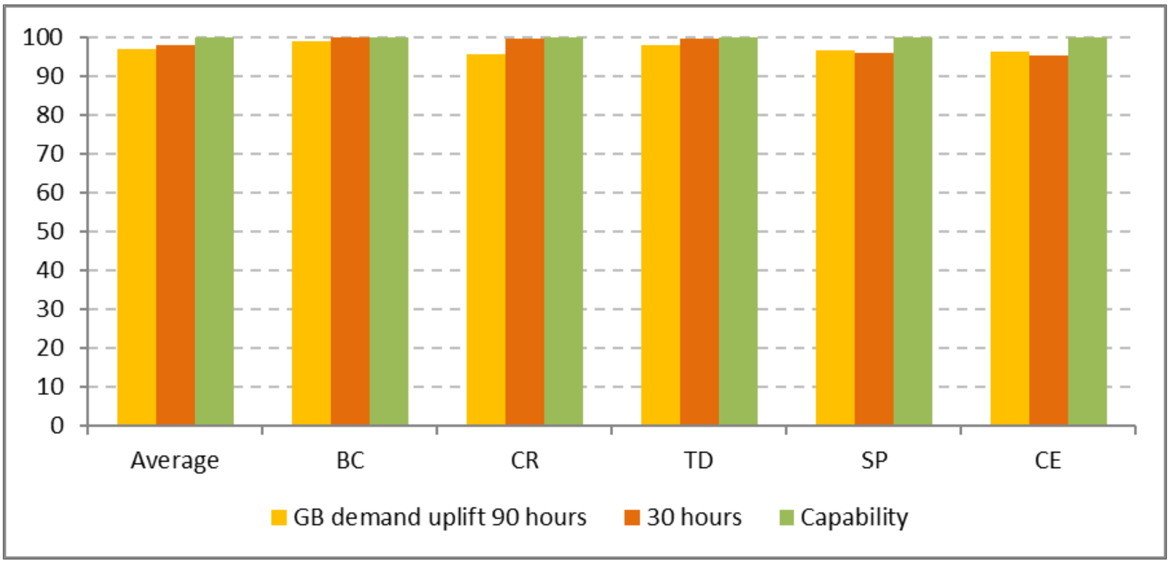


Table 25: Norway interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	97	99	95	98	96	96
30 hours	98	100	100	100	96	95
Capability	100	100	100	100	100	100

Denmark:

Denmark only appears in the Two Degrees scenario for 2023/24 with an import percentage of 35%. Spare capacity is lower indicating that much of these imports originate from other countries.

Figure 31: Denmark interconnector de-rating factors 2023/24

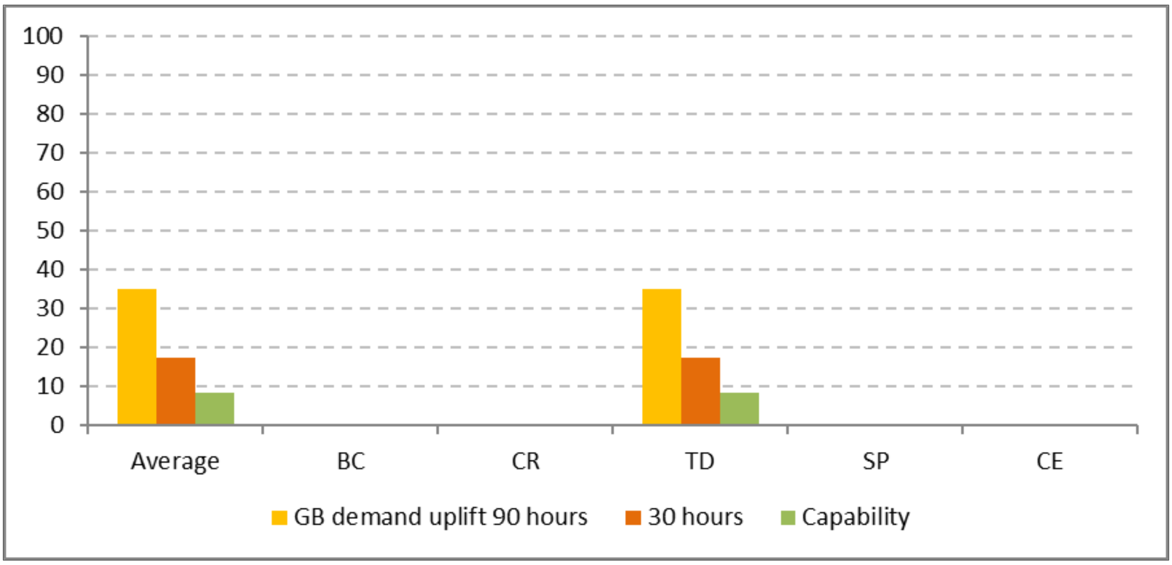


Table 26: Denmark interconnector de-rating factors 2023/24

Calculation	Average	BC	CR	TD	SP	CE
GB demand uplift 90 hours	35	0	0	35	0	0
30 hours	17	0	0	17	0	0
Capability	9	0	0	9	0	0

Summary

This year, it has not been possible to use the FES scenario data without adjusting demand due to the lack of stress periods in Great Britain. BID3 is an economic model so if Great Britain has a surplus of generation the model will export and not import. It would not provide any information on the potential for imports. Therefore, demand in Great Britain was increased to ensure that enough stressed periods were available to represent 3 hours LOLE. As a 30-year history was modelled this is 3 hours * 30 years = 90 hours. A further set of results using the 30 hours with the lowest margins in Great Britain was produced as a sensitivity. The range has been selected from the maximum and minimum of the results from the 90-hour demand uplift (see Table 27). The 30 hour and capability figures have not been used to create these ranges but provide additional context to understanding the results. The capability figures give an indication of how much of the imports originate from the connected country. The capability figures tend to be much lower than the de-rating factors, for Belgium, Netherlands and France, indicating the close interaction of the energy markets in north-west Europe and the importance of a pan-European model rather than modelling each country separately.

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

Table 27: De-rating factor ranges by country

Country	Delivery Year	Low	High
Ireland	2022/23	30	44
	2023/24	24	32
France	2020/21	88	99
	2022/23	66	81
	2023/24	57	79
Belgium	2020/21	75	98
	2022/23	52	65
	2023/24	38	56
Netherlands	2022/23	44	55
	2023/24	30	44
Norway	2022/23	93	99
	2023/24	95	99
Denmark	2023/24	35	35

Four interconnectors have contracts for 2020/21 from the 2016 T-4 auction. These are Moyle, EWIC, IFA and BritNed. Therefore, de-rating factors will not be required for Ireland and the Netherlands for 2020/21.

5. Results and Recommendation for 2020/21 T-1 Auction

This chapter presents the results for 2020/21 only from the modelling of the scenarios and sensitivities relevant to 2020/21. Results for 2022/23 and 2023/24 can be found in Chapters 6 and 7. Further information on capacity requirements in years out to 2033/34 can be found in Section 3.11.

5.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2019 ECR. The agreed sensitivities to model for 2020/21 cover non-delivery, over-delivery, weather, wind, plant availability and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON DEL): 6 sensitivities in 400 MW increments up to 2400 MW
- Over-Delivery (OVER DEL): 4 sensitivities in 400 MW increments up to 1600 MW

5.2 Results

Table 28 below shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All cases modelled take account of capacity market units awarded contracts covering 2020/21 in the 2020/21 T-4 auction and units awarded multi-year contracts in the 2018/19 and 2019/20 T-4 auctions covering 2020/21 that are now known not to be able to honour their contracts – this known non-delivery totals 4.9 GW (de-rated). Also, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded contracts in the 2020/21 T-4 auction has been reduced by around 0.4 GW.

In addition, for contracted transmission connected units, the scenarios and sensitivities (except high and low availability) assume a previously contracted capacity based on de-rated Transmission Entry Capacity (TEC) values and updated de-rating factors that are around 1.2 GW lower in aggregate than the contracted values in the CM register.

These changes have reduced the estimated previously contracted capacity for 2020/21 by 6.5 GW from the reported[36] figure of 58.9 GW down to 52.4 GW. Furthermore, the scenarios assume between 0 and 3.1 GW (de-rated) of additional capacity market units awarded capacity agreements covering 2020/21 in previous T-4 auctions that are not able to honour their agreements. No additional non-delivery is assumed in Steady Progression and the Base Case (0 GW) while Community Renewables assumes the highest level of additional non-delivery (3.1 GW).

Table 28: Modelled de-rated capacities and peak demands – 2020/21

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Warm Winter	BC_WARM	-5.0	64.1	52.4	0.0	59.1	58.9
High Availability	BC_HIGH_AVAIL	-4.4	65.6	54.0	0.0	61.2	58.9
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	-4.1	66.2	52.4*	1.6	62.0	58.9
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	-3.7	65.8	52.4*	1.2	62.0	58.9
Low Demand	BC_LOW_DEMAND	-3.7	64.3	52.4	0.0	60.6	57.7
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	-3.3	65.4	52.4*	0.8	62.0	58.9
High Wind	BC_HIGH_WIND	-3.1	64.9	52.4	0.0	61.9	58.9
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	-2.9	65.0	52.4*	0.4	62.0	58.9
Base Case	BC	-2.5	64.6	52.4	0.0	62.0	58.9
Non Delivery Sensitivity: -400	BC_NON_DEL_400	-2.1	64.2	52.4*	-0.4	62.0	58.9
Cold Winter	BC_COLD	-1.9	64.8	52.4	0.0	62.9	58.9
Low Wind	BC_LOW_WIND	-1.8	64.1	52.4	0.0	62.3	58.9
Non Delivery Sensitivity: -800	BC_NON_DEL_800	-1.7	63.8	52.4*	-0.8	62.0	58.9
Two Degrees	TD	-1.4	63.1	50.8	0.0	61.7	58.3
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	-1.3	63.4	52.4*	-1.2	62.0	58.9
High Demand	BC_HIGH_DEMAND	-1.3	64.9	52.4	0.0	63.5	60.1
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	-0.9	63.0	52.4*	-1.6	62.0	58.9
Low Availability	BC_LOW_AVAIL	-0.7	63.5	50.9	0.0	62.8	58.9
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	-0.5	62.6	52.4*	-2.0	62.0	58.9
Community Renewables	CR	-0.5	61.9	49.3	0.0	61.4	57.7
Consumer Evolution	CE	-0.4	64.0	51.6	0.0	63.6	59.4
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	-0.1	62.2	52.4*	-2.4	62.0	58.9
Steady Progression	SP	0.1	64.7	52.4	0.0	64.9	60.0

Scenario Colour Key
- Two Degrees
- Steady Progression
- Community Renewables
- Consumer Evolution
- Base Case

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

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

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

The warm winter and Steady Progression scenario define the extremes of the capacity to secure range for 2019/20 (-5.0 GW to 0.1 GW). In all cases except Steady Progression, the capacity to secure is negative indicating that sufficient capacity has already been secured in previous actions to meet the 3 hours LOLE Reliability Standard.

[36] See page 8 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20Results%20Report%20-%20T-4%202016.pdf

5.3 Recommended Capacity to Secure

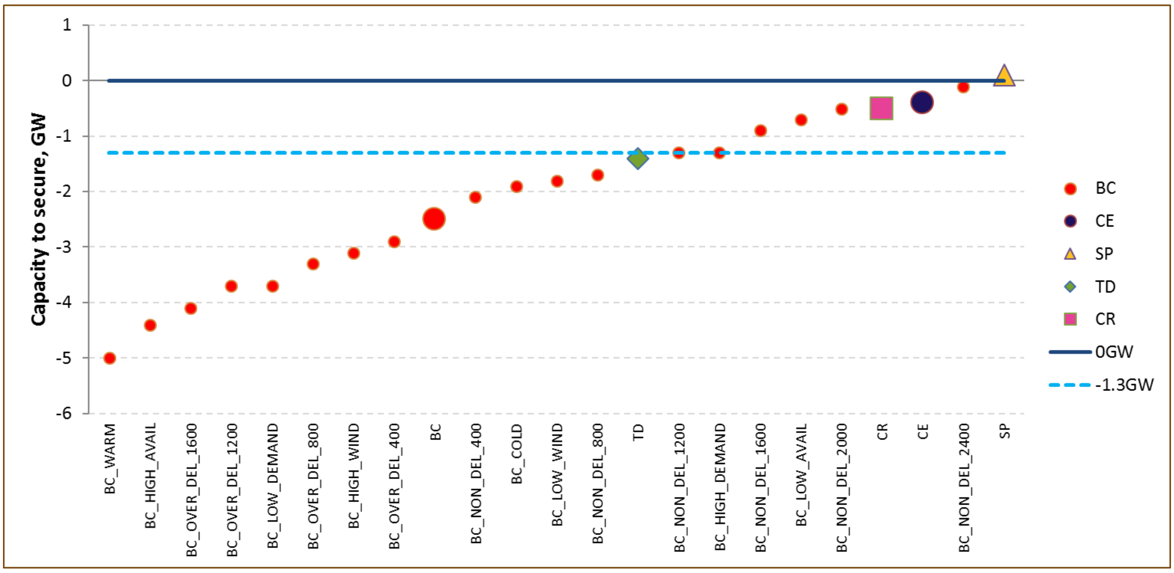
Table 28 above shows the capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2020/21 the actual conditions matched a different model run then capacity will have either been over or under secured, resulting in an LOLE higher or lower than 3 hours. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to secure value in 2020/21 taking account of the costs of under or over securing for all potential outcomes. If the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR).

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

The outcome of the Least Worst Regret calculation applied to all of the scenarios and sensitivities is a capacity to secure for 2020/21 of -1.3 GW derived from the requirement of the nearest Base Case sensitivity (1200 MW non-delivery / high demand) to the Two Degrees requirement (-1.4 GW) selected by the LWR tool. This outcome excludes any capacity secured for 2020/21 in earlier T-4 auctions assumed in the Base Case. As per the conclusion of the T-1 LWR development project (see section 2.5.2), since the outcome of the LWR analysis is a negative capacity, we recommend a target of **0 GW**.

Figure 32 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR outcome (-1.3 GW) and recommendation (0 GW). Scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. The FES scenarios have a less negative requirement than the Base Case due to additional non-delivery assumed in these scenarios and / or higher peak demand. Note that our recommendation concentrates on the target capacity alone.

Figure 32: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2020/21



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

5.3.1 Covered range

We consider that a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2020/21, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the above chart, securing a capacity of 0 GW (not running the auction) would result in 22 out of 23 cases being covered.

5.3.2 Adjustments to Target Capacity

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

- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW.

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

Therefore, if the auction is run, the final auction target in the 2020/21 T-1 auction could be:

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

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

5.3.3 Comparison with original 2020/21 T-1 requirement

In our 2016 Electricity Capacity Report, we recommended a capacity to secure for 2020/21 of 49.7 GW derived from the 2GW non-delivery sensitivity. The Secretary of State initially adjusted the target to 52.6 GW of which back 0.6 GW was held back for the 2020/21 T-1 auction leaving an initial target capacity of 52.0 GW for the T-4 auction. Following pre-qualification, the 2020/21 target was reduced by the Secretary of State by 0.3 GW to 52.3 GW of which 0.6 GW was held back for the 2020/21 T-1 auction leaving a final target capacity of 51.7 GW for the 2020/21 T-1 auction. In total, 2.6 GW (net) of adjustments were made to the target for 2020/21 compared to the 2016 ECR to account for changes in opted-out and operational capacity following prequalification compared to the 2016 Base Case. This net adjustment comprised of:

- 2.0 GW (net) relating to prequalification information or other information received after the ECR was submitted covering previously contracted capacity with multi-year contracts (assumed to be operational in our 2016 ECR modelling) defaulting on formal milestones (1.75 GW), autogeneration assumed to be outside of the CM participating in prequalification (0.45 GW), long term STOR not participating in prequalification CM (-0.1 GW) and capacity declaring itself opted out and operational for 2020/21 in prequalification (-0.1 GW).
- An additional 0.6 GW (net) adjustment made by the Secretary of State relating to uncertainty over autogeneration assumed not to bid in to the CM, growth in small scale renewables capacity that did not have support and different assumptions (than the 2016 ECR) as to the availability of certain plant in 2020/21.

In general, when compared to the analysis for 2020/21 in the 2016 ECR that ultimately led to the 0.6 GW set aside by the Secretary of State for the T-1 auction, the 2019 ECR LWR outcome for 2020/21 is 1.9 GW lower than the 0.6 GW set aside. This difference is the result of the following increases and decreases.

The increases total 4.5 GW:

- Additional non-delivery in the 2019 Base Case than the 2016 Base Case, totalling 1.9 GW in 2020/21 (this is part of the 4.9 GW total known non-delivery - see 5.2).
- A 0.4 GW increase due to the revised de-rating factors for duration-limited storage contracted in the 2020/21 T-4 auction.
- The remaining contracted capacity from previous T-4 auctions being 1.2 GW greater than the de-rated TEC (see 5.2).
- A 0.2 GW increase due to a higher reserve for largest infeed loss than the 2016 Base Case.
- A 0.8 GW increase relating to lower levels of assumed opted-out or ineligible (below 2 MW) autogeneration[37] than the 2016 Base Case.

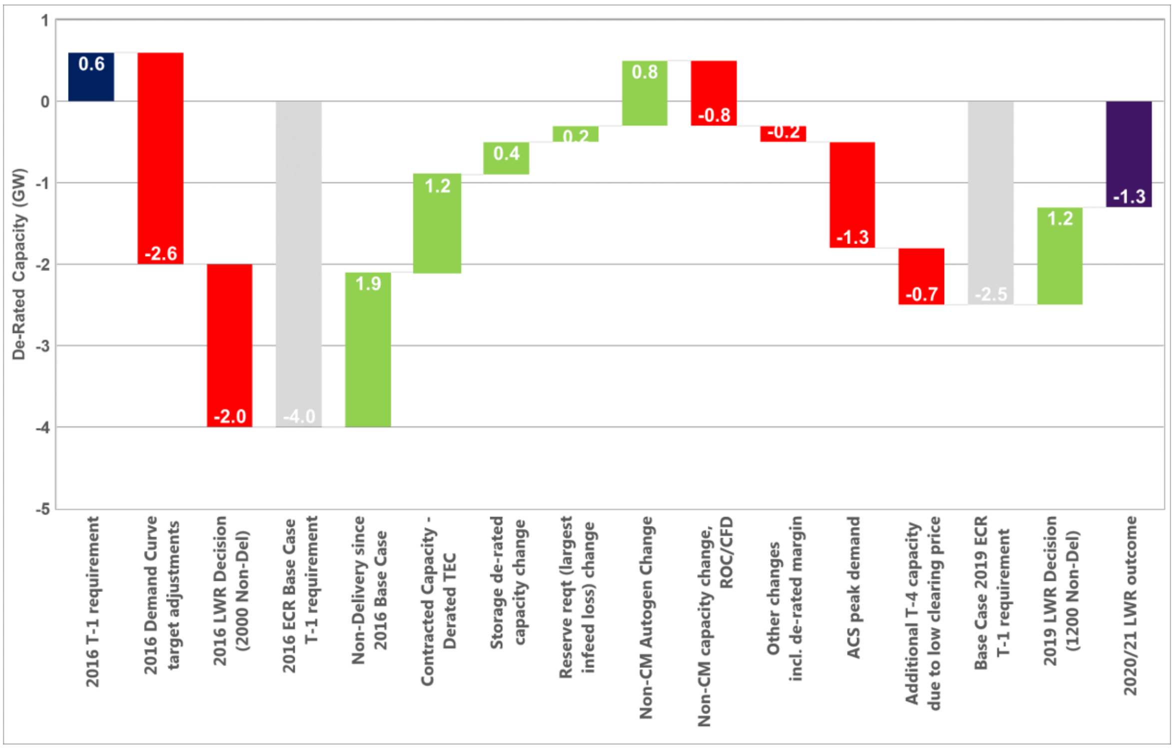
The decreases total 6.4 GW:

- A change in the scenarios and sensitivities modelled resulting in the LWR outcome difference from the Base Case being 0.8 GW lower (1.2 GW non-delivery compared to 2 GW non-delivery).
- A 1.3 GW reduction due to a lower peak demand in 2020/21 compared to the 2016 Base Case (see
-
- Figure 34 below).
- A reduction in requirement from over-securing in the 2020/21 T-4 auction by 0.7 GW due to a low clearing price.
- A 0.8 GW reduction resulting from higher non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely comprised of increased biomass and hydro capacity offset by lower contributions at peak from wind (due in part to the revised wind scaling factor) and from landfill gas.
- 2.6 GW net reduction relating to the demand curve adjustments made in 2016 following prequalification for the T-4 auction [to account for changes in ineligible / opted-out and operational capacity from the 2016 Base Case - see 5.3.3 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 2019 Base Case generation assumptions are different to the 2016 Base Case assumptions.
- A 0.2 GW net reduction due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2016 Base Case and rounding).

The following waterfall chart, Figure 33, shows how the original 0.6 GW set aside for the 2020/21 T-1 auction (derived from the 2016 2000 MW non-delivery sensitivity) has changed into a LWR outcome of -1.3 GW (derived from the 2019 Base Case 1200 MW non-delivery sensitivity) as a result of the 1.9 GW net decrease described above.

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

Figure 33: Comparison with original 2020/21 T-1 requirement (de-rated)

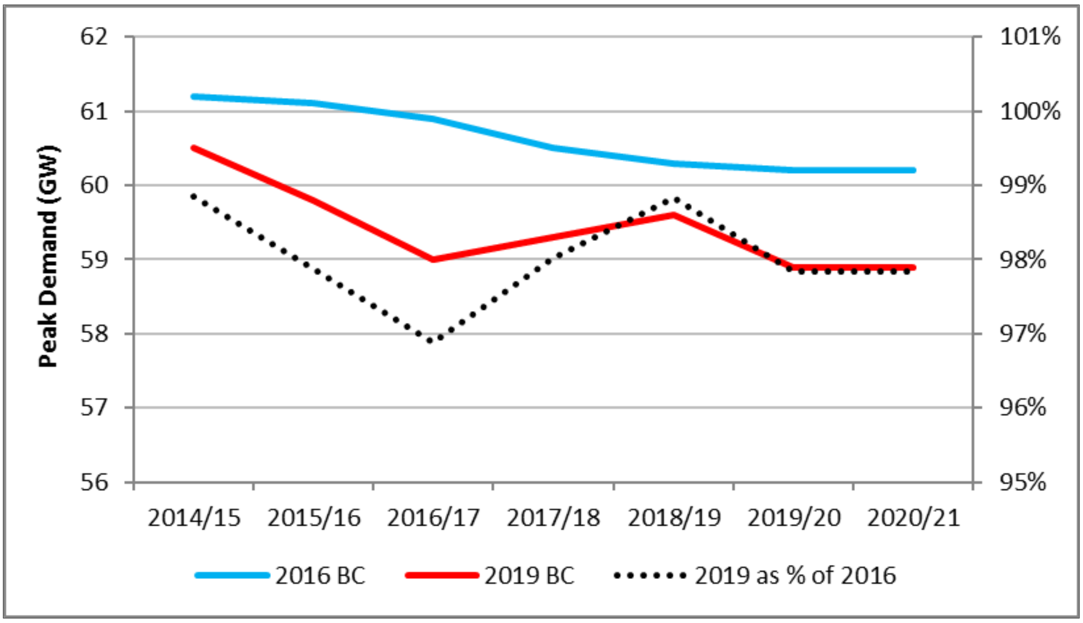


Note: intermediate totals in grey above show requirements for 2016 Base Case and 2019 Base Case

As highlighted above, since the 2016 ECR, the peak demand for 2020/21 has reduced by 1.3 GW.

Figure 34 compares the underlying ACS peak demand in the 2019 Base Case (2019 BC) to the underlying ACS peak demand in the 2016 Base Case (2016 BC) scenario over the period from 2014/15 to 2020/21, which illustrates that the 2016 Base Case peak demand declined slowly over the period from a higher starting point whereas the 2019 Base Case peak demand dropped over the period to 2016/17 from a lower starting point and remains relatively flat from 2016/17 to 2020/21.

Figure 34: Peak Demand Comparison (2019 ECR v 2016 ECR)



Since 2016, our view of underlying demand has evolved as more information or new methods have become available to us. As underlying demand is not metered, it is derived using a mix of metered and researched data.

The key changes since 2016 are as follows:

- ACS Peak Restricted National Demand on the transmission system (the starting point for demand creation) was revised using a single up-to-date method and the latest data available.
- We continue to dedicate significant resource to obtain better information on non-transmission generation (which meets demand), using Electralink, DNO and third party information. Using this evidence, we have revised down our view of CHP generation output at peak (offset slightly by more wind and 'other' generation at peak).
- We continue to dedicate significant resource to obtain better information on demand side response – we now believe approximately 50% of TRIAD response is generation, so we have revised down demand in order to reduce potential double counting of the effect of non-transmission generation.

In 2016, we forecast residential demand to fall slightly, offset by EV charging and early adoption of heat pumps in order to meet carbon targets. EU halogen legislation had been delayed.

Demand was forecast to fall slowly in residential, industrial & commercial demand due to increasing energy efficiency and slow economic growth.

By 2019, EU halogen legislation has been reinstated, and decarbonisation of heat has been slower than forecast. Our EV peak demand projections are similar between 2016 and 2019.

In 2019, residential demand is forecast to fall due to increasing energy efficiency and this drives overall demand lower (despite a slow forecast increase in industrial & commercial demand).

This highlights the need to continue to develop our methodologies and data sources to enhance our understanding of peak demand. The letter written under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology[38].

5.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities, a question was raised around how sensitive the LWR decision was to the sensitivities included e.g. maximum level of non-delivery. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 29 below.

Table 29: Sensitivity of LWR outcome (-1.3 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-Warm	-Warm -H. Avail	- Warm -H. Avail +2.0 OD	-SP	-SP -2.4 ND	+2.8 ND
2020/21 outcome	-1.3	-1.3	-1.3	-1.9	-1.9	-1.3

Removing the lowest case (warm winter) did not change the outcome (-1.3 GW) as this was the requirement from the nearest Base Case sensitivity to the original LWR tool selection (-1.4 GW for TD). Removing the next lowest case (High Availability) and adding an additional over-delivery case (2.0 GW) did not change the outcome either (-1.3 GW). Removing the highest case (SP) reduced the LWR tool outcome by 0.6 GW to -1.9 GW. Removing next highest case (the 2.4 GW ND case) also resulted in a reduced outcome of -1.9 GW. Increasing the maximum non-delivery to 2.8 GW did not change the original outcome (-1.3 GW). Hence the outcome remains fairly stable when removing either the lowest or highest sensitivities or adding additional OD and ND sensitivities.

Although the LWR outcome is relatively stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.4 GW to reflect the risk associated with coal and gas closures, embedded benefits, unproven DSR and interconnection.

To set this in context, for the 2020/21 T-4 auction around 4.9 GW of non-delivery has been observed including capacity awarded multi-year agreements in the 2018/19 and 2019/20 T-4 auctions[39] that no longer has multi-year agreements.

[38] To be published at https://www.emrdeliverybody.com/cm/home.aspx
[39] Note that the CM rules and penalty regime have changed since the 2018/19 T-4 auction

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

6. Results and Provisional Recommendation for 2022/23 T-3 Auction

The 2022/23 T-4 auction planned for 2019 was suspended following the 15 November 2018 decision of the General Court of the Court of Justice of the European Union annulling State aid approval for the GB Capacity Market. The Government is now considering replacing the suspended T-4 auction with a new T-3 auction to secure capacity for delivery in 2022/23. We understand that if the Government proceeds with this proposal, National Grid ESO will be required to prepare an annex to this report which includes a recommendation as to the target capacity for the T-3 auction.

This chapter presents a provisional recommendation for 2022/23 from the modelling of the scenarios and sensitivities relevant to the proposed 2022/23 T-3 auction, updating the recommendation presented for the T-4 auction in the 2018 ECR. This provisional recommendation will be confirmed or updated if the Government decides to proceed with the T-3 auction and requires National Grid ESO to prepare an annex to this report.

Results for 2020/21 and 2023/24 can be found in Chapters 5 and 7. Further information on capacity requirements in years out to 2033/34 can be found in Section 3.11.

6.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2019 ECR. The agreed sensitivities to model for 2022/23 cover non-delivery, over-delivery, weather, wind and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON DEL): 6 sensitivities in 400 MW increments up to 2400 MW
- Over-Delivery (OVER DEL): 4 sensitivities in 400 MW increments up to 1600 MW

6.2 Results

Table 30 shows the modelling results sorted in order of de-rated capacity required to meet the 3 hours LOLE Reliability Standard. It also shows the capacity outside of the CM (including previously contracted capacity assumed for each case), the total de-rated capacity and ACS peak demand.

All the scenarios and sensitivities modelled take account of capacity market units awarded multi-year capacity agreements covering 2022/23 in previous T-4 auctions that have had their contracts terminated – this totals 1.8 GW (de-rated). In addition, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded multi-year contracts in the 2020/21 T-4 auction has been reduced by around 0.4 GW. These two changes have reduced the estimated previously contracted capacity for 2022/23 by 2.2 GW from the reported[40] figure of 6.7 GW down to 4.5 GW.

No additional non-delivery is assumed in any of the FES scenarios and Base Case.

Table 30: Modelled de-rated capacities and peak demands - 2022/23

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Community Renewables	CR	42.3	18.6	4.5	0.0	60.9	56.5
Warm Winter	BC_WARM	42.6	18.0	4.5	0.0	60.6	58.8
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	43.4	19.6	4.5*	1.6	62.9	58.8
Two Degrees	TD	43.7	18.6	4.5	0.0	62.3	58.1
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	43.8	19.2	4.5*	1.2	62.9	58.8
Low Demand	BC_LOW_DEMAND	43.8	18.0	4.5	0.0	61.8	57.6
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	44.2	18.8	4.5*	0.8	62.9	58.8
High Wind	BC_HIGH_WIND	44.4	18.6	4.5	0.0	63.0	58.8
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	44.6	18.4	4.5*	0.4	62.9	58.8
Base Case	BC	45.0	18.0	4.5	0.0	62.9	58.8
Non Delivery Sensitivity: -400	BC_NON_DEL_400	45.4	17.6	4.5*	-0.4	62.9	58.8
Cold Winter	BC_COLD	45.6	18.1	4.5	0.0	63.7	58.8
Low Wind	BC_LOW_WIND	45.7	17.3	4.5	0.0	63.0	58.8
Non Delivery Sensitivity: -800	BC_NON_DEL_800	45.8	17.2	4.5*	-0.8	62.9	58.8
Consumer Evolution	CE	45.9	17.8	4.5	0.0	63.7	59.7
High Demand	BC_HIGH_DEMAND	46.1	18.0	4.5	0.0	64.2	60.0
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	46.2	16.8	4.5*	-1.2	62.9	58.8
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	46.6	16.4	4.5*	-1.6	62.9	58.8
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	47.0	16.0	4.5*	-2.0	62.9	58.8
Steady Progression	SP	47.2	17.6	4.5	0.0	64.9	60.9
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	47.4	15.6	4.5*	-2.4	62.9	58.8

Scenario Colour Key

- Two Degrees
- Steady Progression
- Community Renewables
- Consumer Evolution
- Base Case

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

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

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

The Community Renewables scenario and 2400 MW non-delivery sensitivity define the extremes of the provisional capacity to secure range for 2022/23 (42.3 GW to 47.4 GW).

[40] See page 9 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20T-4%20Results%20(Delivery%20Year%2021-22)%2020.02.2018.pdf

6.3 Provisional Recommendation

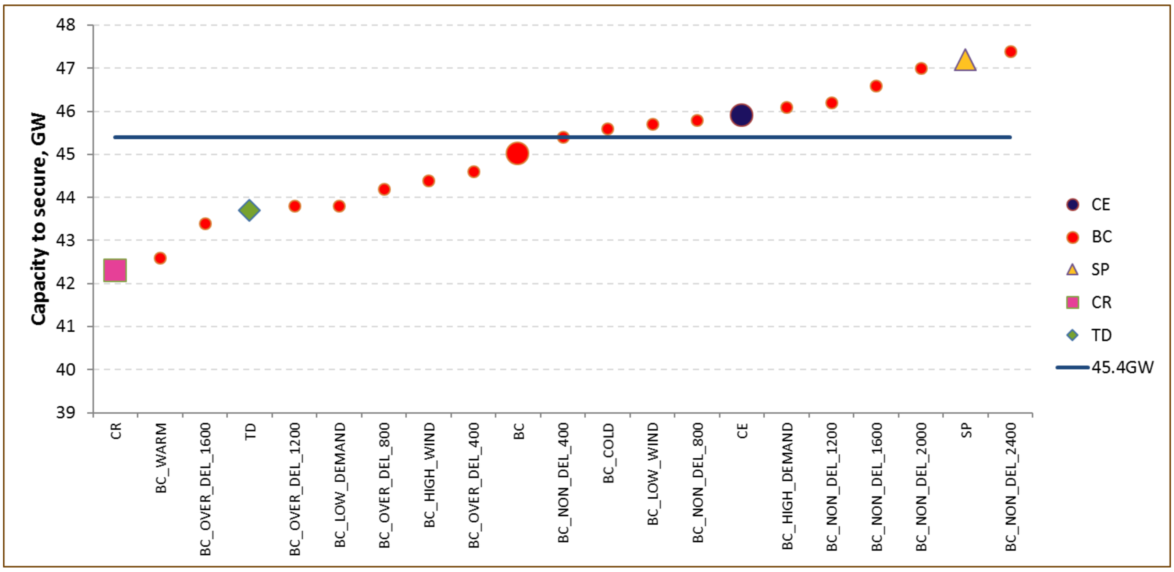
Table 30 shows the de-rated capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2022/23, the actual conditions matched a different model run, then capacity will have either been over or under secured, resulting in an LOLE lower or higher than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a provisional recommendation of capacity to secure in 2022/23, taking account of the costs of under or over securing for all potential outcomes.

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

The outcome of the LWR calculation applied to all of National Grid SO's scenarios and sensitivities is a provisional recommendation of the capacity to secure for 2022/23 of **45.4 GW** derived from the requirement of the Base Case 400 MW non-delivery sensitivity. This provisional recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The provisional recommendation also excludes any capacity secured for 2022/23 in earlier T-4 auctions that is assumed in the Base Case.

Figure 35 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR provisional recommendation. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note the provisional recommendation concentrates on the target capacity alone.

Figure 35: Least Worst Regret provisional recommended capacity to secure compared to individual scenario/sensitivity runs – 2022/23



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

6.3.1 Covered range

We consider that a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and it was to occur in 2022/23, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the chart, securing a capacity of 45.4 GW would result in 11 out of 21 cases being covered.

6.3.2 Adjustments to Provisional Recommendation

The provisional recommendation in this report will not necessarily be the capacity auctioned. If the Secretary of State decides to hold a T-3 auction, the target capacity will also be a decision for the Secretary of State, included in the Final Auction Guidelines published after pre-qualification. To obtain the capacity auction requirement, a number of adjustments to the provisional figure or range would need to be made (e.g. denoted by v, w, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with Long Term STOR contracts that opts not to surrender those contracts would need to be excluded (pre-qualification could change this) – vGW.
- Government (upon confirming auction parameters to National Grid ESO prior to auction guidelines) would need to determine how much capacity to hold back for the 2022/23 T-1 auction – wGW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) would need to determine DSR to opt-out but remain operational – xGW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) would need to determine distributed generation to opt out but remain operational – yGW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) would need to determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – zGW.*

Therefore, the provisional capacity to secure through the 2022/23 T-3 auction could be:

- 45.4 GW - v - w - x - y - z.

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

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

Given that it is unlikely that the marginal capacity in the auction would result in an LOLE of exactly 3 hours, the demand curve for the auction would result in a capacity from a range around the target capacity. Thus, a provisional recommendation of 45.4 GW could result in a differing capacity volume depending on the clearing price set by the marginal capacity. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any issues with this value could be reconciled appropriately in the T-1 auction.

6.3.3 Comparison with 2022/23 T-4 recommendation

In our 2018 Electricity Capacity Report, we recommended a capacity to secure for 2022/23 of 46.7 GW, 0.9 GW above our Base Case requirement of 45.8 GW, which assumed 4.4 GW of previously contracted capacity (net of 0.2 GW additional non-delivery and 0.3 GW storage de-rating factor change).

In general, when compared to the analysis for 2022/23 in the 2018 ECR, the 2019 ECR provisional recommendation for 2022/23 is 1.3 GW lower. This difference is the result of the following increases and decreases.

The increases total 0.9 GW:

- A 0.1 GW increase in reserve for largest infeed loss compared to the 2018 Base Case.
- A 0.1 GW increase resulting from lower non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely comprised of slightly lower contributions at peak from wind (due in part to the revised wind scaling factor) partly offset by slightly higher biomass and other capacity.
- A 0.2 GW increase resulting from lower assumed opted-out or ineligible (below 2 MW) autogeneration[41].
- An increase of 0.1 GW due to a small change in estimated de-rated storage awarded multi-year contracts in 2020/21 (0.4 GW reduction in 2019 ECR v 0.3 GW reduction in 2018 ECR).
- A 0.4 GW increase due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2018 Base Case and rounding).

The decreases total 2.2 GW:

- A decrease of 0.5 GW due primarily to a different range of sensitivities and scenarios (e.g. a maximum of 2.4 GW non-delivery in the 2019 ECR compared to a maximum of 2.8 GW in the 2018 ECR) resulting in a different sensitivity (0.4 GW non-delivery) setting the LWR provisional recommendation (compared to the cold winter sensitivity setting the LWR requirement in the 2018 ECR).

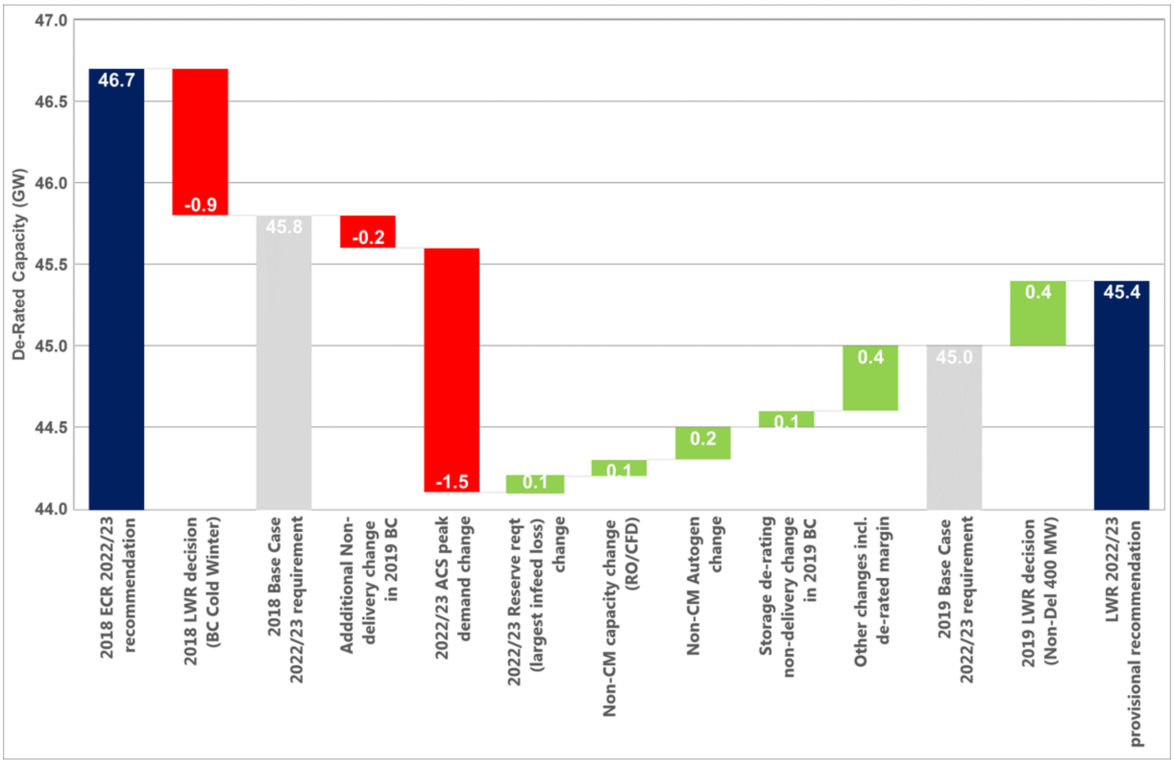
[41] Note that unsupported capacity under 2 MW can enter the auction if it is combined with other capacity by an aggregator to give a total above 2 MW

- A 0.2 GW reduction resulting from a change in assumed additional non-delivery (0 GW assumed in 2019 ECR v 0.2 GW assumed in 2018 ECR)
- A 1.5 GW reduction due to a lower peak demand for 2022/23 compared to the 2018 Base Case (due to reduced EV charging at peak, reduced residential demand, change in annual to peak correlation and the residential halogen lighting ban – see Section 3.3 for more details).

This analysis highlights the risk of further non-delivery (up to a maximum of 2.4 GW in the most extreme non-delivery sensitivity). However, we note that by highlighting the risk in this report, some of this non-delivery may be prevented. This in turn would reduce the demand curve target in the T-1 auction, which would be reassessed in the 2021 ECR.

The following waterfall chart, Figure 36, shows how the original 46.7 GW requirement for the 2022/23 T-4 auction (derived from the 2018 Base Case cold winter sensitivity) has changed into a provisional recommendation of 45.4 GW (derived from the 2019 Base Case 400 MW non sensitivity) as a result of the 1.3 GW net reduction described above.

Figure 36: Comparison with recommended 2022/23 T-4 requirement in 2018 ECR



Note: intermediate totals in grey above show requirements for 2018 Base Case and 2019 Base Case

6.3.4 Robustness of LWR approach to sensitivities considered

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

Table 31: Sensitivity of LWR provisional recommendation (45.4 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-CR	-CR - Warm	-CR - Warm +2.0 OD	-2.4 ND	-2.4 ND -SP	+2.8 ND
2022/23 provisional recommendation	45.6	45.8	45.7	45.4	45.4	45.7

Removing the lowest case (CR) increased the provisional recommendation by 0.2 GW to 45.6 GW. Removing the next lowest case (warm winter) as well increased the provisional recommendation to 45.8 GW. Adding an additional over-delivery case (2.0 GW) to this brought the provisional recommendation back down slightly to 45.7 GW. For a maximum non-delivery of 2.0 GW (i.e. removing the 2.4 GW ND case), there was no impact on the provisional recommendation (45.4 GW). Removing the next highest case (SP) also resulted in no change (45.4 GW). Increasing the maximum non-delivery to 2.8 GW increased the provisional recommendation by 0.3 GW to 45.7 GW. Hence the provisional recommendation remains stable when removing either the lowest or highest sensitivity or adding additional OD and ND sensitivities.

Although the LWR outcome is relatively stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.4 GW to address the risk associated with coal and gas closures, embedded benefits, unproven DSR and interconnection.

To set this in context, for the 2020/21 T-4 auction around 4.9 GW of non-delivery has been observed including capacity awarded multi-year agreements in the 2018/19 and 2019/20 T-4 auctions[42] that no longer has multi-year agreements.

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

7. Results and Recommendation for 2023/24 T-4 Auction

This chapter presents the results for 2023/24 only from the modelling of the scenarios and sensitivities relevant to the 2023/24 T-4 auction. Results for 2020/21 and 2022/23 can be found in Chapters 5 and 6. Further information on capacity requirements in years out to 2033/34 can be found in Section 3.11.

7.1 Sensitivities to model

The analysis assumes that the FES scenarios will cover multivariate uncertainty by incorporating ranges for annual and peak demand, DSR, storage, interconnection and generation with the sensitivities covering uncertainty in single variables. Chapter 3 describes the scenarios and sensitivities modelled for the 2019 ECR. The agreed sensitivities to model for 2023/24 cover non-delivery, over-delivery, weather, wind and demand:

- Low Wind Output at times of cold weather (LOW WIND)
- High Wind Output at times of cold weather (HIGH WIND)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON DEL): 6 sensitivities in 400 MW increments up to 2400 MW
- Over-Delivery (OVER DEL): 4 sensitivities in 400 MW increments up to 1600 MW

7.2 Results

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

All the scenarios and sensitivities modelled take account of capacity market units awarded multi-year capacity agreements covering 2023/24 in previous T-4 auctions that have had their contracts terminated – this totals 1.8 GW (de-rated). In addition, since the 2020/21 T-4 auction, the de-rating factors for duration limited storage technologies have been revised. As a result of these revisions, our estimate of the de-rated capacity of duration limited storage capacity awarded multi-year contracts in the 2020/21 T-4 auction has reduced by around 0.4 GW. These two changes have reduced the estimated previously contracted capacity for 2023/24 by 2.2 GW from the reported[43] figure of 6.7 GW down to 4.5 GW. No additional non-delivery is assumed in any of the scenarios.

[43] See page 9 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20T-4%20Results%20(Delivery%20Year%2021-22)%2020.02.2018.pdf

Note that since the 2022/23 T-3 auction has not yet taken place, an adjustment to our recommendation for 2023/24 may be required after the 2022/23 T-3 auction to account for any capacity awarded multi-year agreements covering 2023/24 (see 7.3.2).

Table 32: Modelled de-rated capacities and peak demands - 2023/24

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW)	Total derated capacity (GW)	ACS Peak (GW)
Community Renewables	CR	40.9	18.9	4.5	0.0	59.8	56.2
Warm Winter	BC_WARM	41.7	18.2	4.5	0.0	59.8	58.9
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	42.4	19.8	4.5*	1.6	62.3	58.9
Two Degrees	TD	42.8	18.9	4.5	0.0	61.7	58.3
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	42.8	19.4	4.5*	1.2	62.3	58.9
Low Demand	BC_LOW_DEMAND	42.9	18.2	4.5	0.0	61.1	57.7
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	43.2	19.0	4.5*	0.8	62.3	58.9
High Wind	BC_HIGH_WIND	43.5	18.7	4.5	0.0	62.2	58.9
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	43.6	18.6	4.5*	0.4	62.3	58.9
Base Case	BC	44.0	18.2	4.5	0.0	62.3	58.9
Non Delivery Sensitivity: -400	BC_NON_DEL_400	44.4	17.8	4.5*	-0.4	62.3	58.9
Cold Winter	BC_COLD	44.7	18.2	4.5	0.0	62.9	58.9
Low Wind	BC_LOW_WIND	44.8	17.5	4.5	0.0	62.2	58.9
Non Delivery Sensitivity: -800	BC_NON_DEL_800	44.8	17.4	4.5*	-0.8	62.3	58.9
High Demand	BC_HIGH_DEMAND	45.2	18.1	4.5	0.0	63.3	60.1
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	45.2	17.0	4.5*	-1.2	62.3	58.9
Consumer Evolution	CE	45.3	17.9	4.5	0.0	63.3	59.9
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	45.6	16.6	4.5*	-1.6	62.3	58.9
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	46.0	16.2	4.5*	-2.0	62.3	58.9
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	46.4	15.8	4.5*	-2.4	62.3	58.9
Steady Progression	SP	46.7	17.8	4.5	0.0	64.5	61.4

Scenario Colour Key
Two Degrees
Steady Progression
Community Renewables
Consumer Evolution
Base Case

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

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

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

The Community Renewables and Steady Progression scenarios define the extremes of the capacity to secure range for 2023/24 (40.9 GW to 46.7 GW).

7.3 Recommended Capacity to Secure

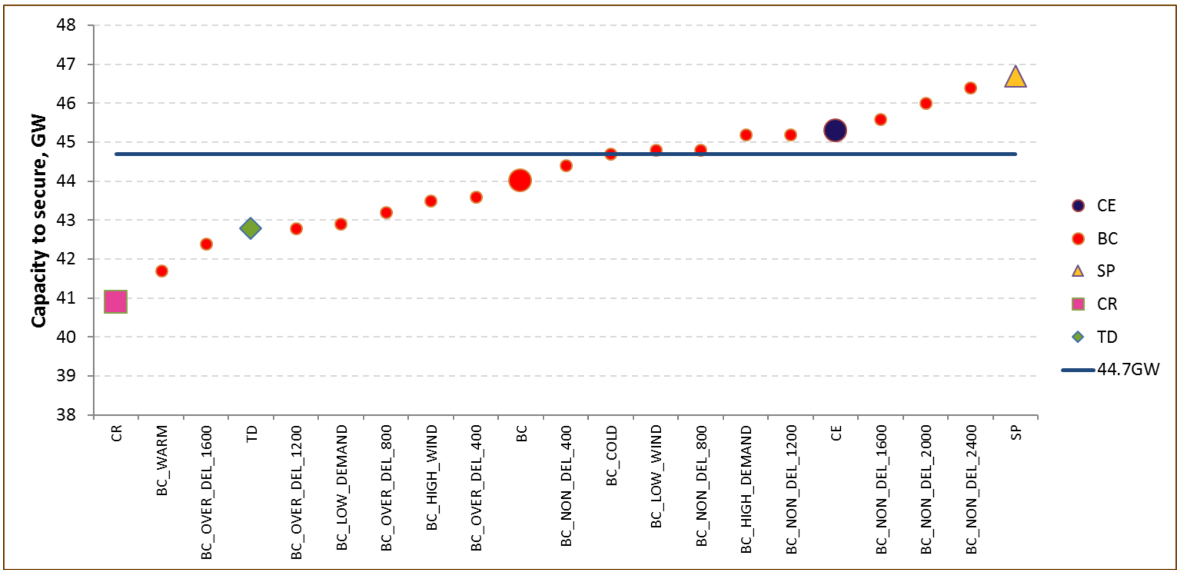
Table 32 shows the de-rated capacity required to meet 3 hours LOLE in each model run. However, if the capacity was selected based on one model run, but in 2023/24, the actual conditions matched a different model run then capacity will have either been over or under secured, resulting in an LOLE lower or higher than 3. The impact of over or under securing capacity can be estimated from the cost of capacity and the cost of unserved energy. The Least Worst Regret (LWR) methodology, agreed with BEIS and the PTE, has been used to select a recommended capacity to secure in 2023/24, taking account of the costs of under or over securing for all potential outcomes.

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

The outcome of the LWR calculation applied to all of National Grid SO's scenarios and sensitivities is a recommended capacity to secure for 2023/24 of **44.7 GW** derived from the requirement of the Base Case cold winter sensitivity. Our recommended target capacity to secure corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. The recommendation also excludes any capacity secured for 2023/24 in earlier T-4 auctions that is assumed in the Base Case.

Figure 37 illustrates the full range of potential capacity requirements (from the scenarios and sensitivities) and identifies the LWR recommendation. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. Note that our recommendation concentrates on the target capacity alone.

Figure 37: Least Worst Regret recommended capacity to secure compared to individual scenario/sensitivity runs – 2023/24



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.

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 is not covered, and it was to occur in 2023/24, then the LOLE could be greater than 3 hours. This could increase the deployment of mitigating actions (voltage reduction, max gen service and emergency assistance from interconnectors) more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections.

As can be seen from the chart, securing a capacity of 44.7 GW would result in 12 out of 21 cases being covered.

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, included in the Final Auction Guidelines published after pre-qualification. To obtain the capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made (e.g. denoted by u, v, w, x, y and z below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in z):

- Capacity with multi-year contracts covering 2023/24 awarded in the 2022/23 T-3 auction – uGW
- Capacity with Long Term STOR contracts that opts not to surrender those contracts needs to be excluded (pre-qualification could change this) – vGW.
- Government (upon confirming auction parameters to National Grid ESO prior to auction guidelines) will determine how much capacity to hold back for the 2023/24 T-1 auction– wGW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine DSR to opt-out but remain operational – xGW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – yGW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – zGW.*

Therefore, the recommended capacity to secure through the 2023/24 T-4 auction could be:

- 44.7 GW - u - v - w - x - y - z.

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

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

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours, the demand curve for the auction will result in a capacity from a range around the target capacity. Thus, a recommended de-rated capacity of 44.7 GW could result in a differing capacity volume depending on the clearing price set by the marginal unit. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any issues with this value can be reconciled appropriately in the T-1 auction.

7.3.3 Comparison with 2022/23 T-4 recommendation

In our 2018 Electricity Capacity Report, we recommended a capacity to secure for 2022/23 of 46.7 GW, 0.9 GW above our Base Case requirement of 45.8 GW which assumed 4.4 GW of previously contracted capacity (net of 0.2 GW additional non-delivery and 0.3 GW storage de-rating factor change).

In general, when compared to the analysis for 2022/23 in the 2018 ECR, the 2019 ECR recommendation for 2023/24 is 2.0 GW lower. This difference is the result of the following increases and decreases.

The increases total 0.6 GW:

- A 0.2 GW increase resulting from lower assumed opted-out or ineligible (below 2 MW) autogeneration[44].
- An increase of 0.1 GW due to a small change in estimated de-rated storage awarded multi-year contracts in 2020/21 (0.4 GW reduction in 2019 ECR v 0.3 GW reduction in 2018 ECR)
- A 0.3 GW increase due to other changes (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2018 Base Case and rounding).

The decreases total 2.6 GW:

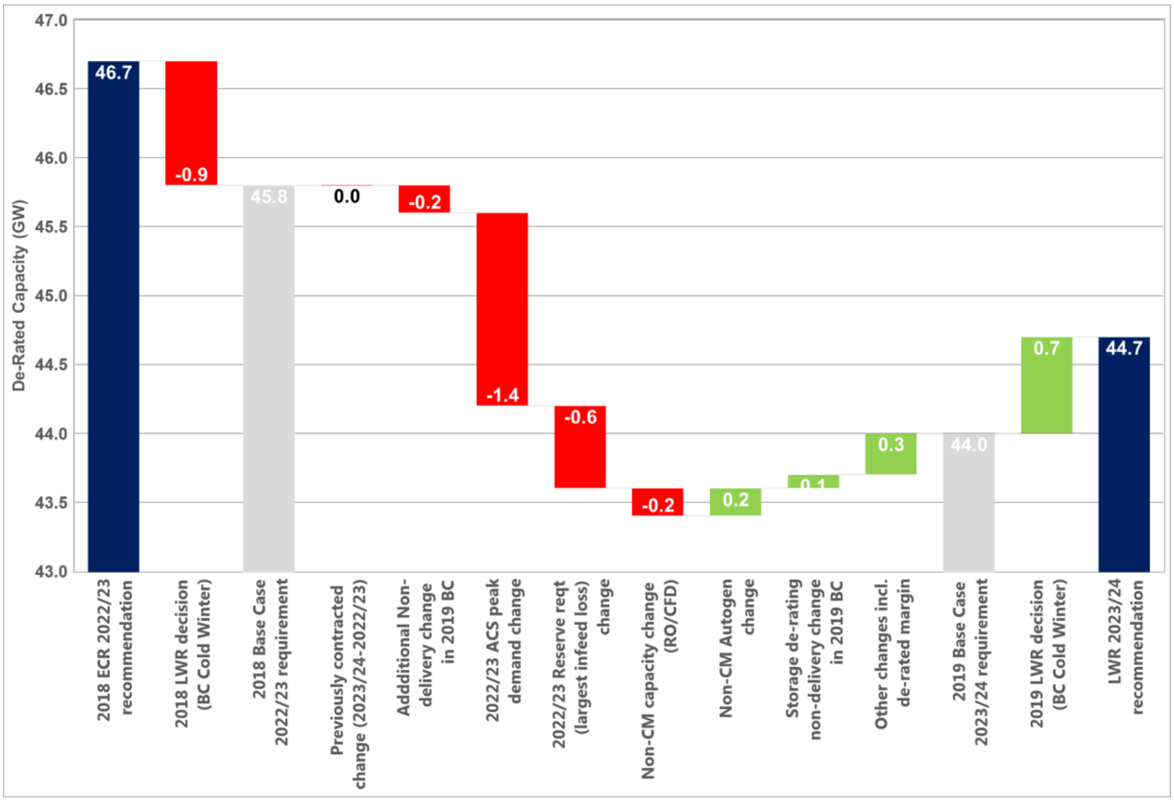
- A decrease of 0.2 GW resulting from a reduced differential of the LWR outcome to the Base Case - the cold winter sensitivity set the LWR requirement in both the 2018 ECR and 2019 ECR but the inclusion of winter 2017/18 in the 2019 analysis has moved the Base Case requirement closer to the cold winter requirement.
- A 0.6 GW decrease in reserve for largest infeed loss compared to the 2018 Base Case.
- A 0.2 GW increase resulting from higher non-CM renewable capacity (see Annex A.4.3 for breakdown). This is largely comprised of slightly higher biomass and other renewable capacity
- A 0.2 GW reduction resulting from a change in assumed additional non-delivery (0 GW assumed in 2019 ECR v 0.2 GW assumed in 2018 ECR)
- A 1.4 GW reduction due to a lower peak demand for 2022/23 compared to the 2018 Base Case (due to reduced EV charging at peak, reduced residential demand, change in annual to peak correlation and the residential halogen lighting ban – see Section 3.3 for more details).

This analysis highlights the risk of further non-delivery (up to a maximum of 2.4 GW in the most extreme non-delivery sensitivity). However, we note that by highlighting the risk in this report, some of this non-delivery may be prevented. This in turn would reduce the demand curve target in the T-1 auction, which will be reassessed in the 2022 ECR.

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

The following waterfall chart, Figure 38, shows how the original 46.7 GW requirement for the 2022/23 T-4 auction (derived from the 2018 Base Case cold winter sensitivity) has changed into a recommended requirement of 44.7 GW (derived from the 2019 Base Case cold winter sensitivity) as a result of the 2.0 GW net reduction described above.

Figure 38: Comparison with recommended 2022/23 T-4 requirement in 2018 ECR



Note: intermediate totals in grey above show requirements for 2018 Base Case and 2019 Base Case

7.3.4 Comparison with 2022/23 T-3 provisional recommendation

Our recommendation for 2023/24 (44.7 GW) is 0.7 GW lower than the provisional recommendation for 2022/23 (45.4 GW). This is mainly due to lower reserve for largest infeed loss (-0.7 GW), a reduction for a higher level of non-CM capacity (-0.3 GW) and a slightly lower de-rated margin for 3 hours LOLE (-0.1 GW) offset by a higher LWR decision compared to the Base Case (+0.3 GW) and a slightly higher peak demand (+0.1 GW).

Section 3.11 shows how the requirement for CM-eligible capacity changes over a 15-year horizon. This section shows that in general across the range of scenarios / sensitivities modelled, there is a gradual decline over the first half of the period as the level of de-rated non-CM (e.g. RO/CfD-supported) capacity increases by more than any growth in peak demand (plus reserve for largest infeed loss). All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. Thereafter the picture is more mixed.

7.3.5 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities a question was raised around how sensitive the LWR decision was to the sensitivities included e.g. maximum level of non-delivery. To address this, we ran the

LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 33.

Table 33: Sensitivity of LWR decision (44.7 GW) to LWR range

Sensitivities Added (+) or Removed (-)	-CR	-CR - Warm	-CR - Warm +2.0 OD	-SP	-SP -2.4 ND	+2.8 ND
2023/24 decision	44.8	45.2	44.8	44.4	44.0	44.7

Removing the lowest case (CR) increased the decision by 0.1 GW to 44.8 GW. Removing the next lowest case (warm winter) as well increased the decision to 45.2 GW. Adding an additional over-delivery case (2.0 GW) to this brought the decision back down to 44.8 GW. Removing the highest case (SP) reduced the LWR tool decision by 0.3 GW to 44.4 GW. Removing next highest case (the 2.4 GW ND case) also resulted in a further reduction to the decision of 0.4 GW to 44.0 GW. Increasing the maximum non-delivery to 2.8 GW did not change the original decision (44.7 GW). Hence the decision remains relatively stable when removing either the lowest or highest sensitivity or adding additional OD and ND sensitivities.

Although the LWR decision is relatively stable when the maximum non-delivery is reduced or increased, we still believe the most robust maximum non-delivery sensitivity is 2.4 GW to address the risk associated with coal and gas closures, embedded benefits, unproven DSR and interconnection.

To set this in context, for the 2020/21 T-4 auction around 4.9 GW of non-delivery has been observed including capacity awarded multi-year agreements in the 2018/19 and 2019/20 T-4 auctions[45] that no longer has multi-year agreements.

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

A. Annex

A.1 Demand Methodology

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

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

Domestic

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

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

- **Resistive heat and hot water:** A methodology has been applied where we use the thermal efficiency of the housing stock rather than just the insulation to inform our modelling. The 2019 scenarios have been revised based on recent information. In our faster decarbonisation scenarios, the average household thermal efficiency will be much improved on today's average. Current electrical heat demand comes from published statistics[46].

- **Heat pumps:** In the 2018 scenarios, we considered how heat might decarbonise in a decentralised (Community Renewables) or centralised (Two Degrees) scenario. The approach was well received and 2019 builds on this. In Community Renewables, heat pumps (air source, ground source, hybrids) and district schemes are the main form of decarbonised heat, with some gas and low carbon fuel heating. In Two Degrees, carbon capture, utilisation and storage facilitates steam methane reformation as a low carbon source of hydrogen. In this scenario, there is high penetration of residential hydrogen heating, but heat pump and other technology penetration is still significant. Based on whole system work and feedback, there are increased numbers of hybrids in the 2019 scenarios. All

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

scenarios are a patchwork of heating technologies due to regional variations and the expectation that no single technology will dominate low carbon heat.

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

Industrial

Economic data provided by Oxford Economics in December 2018 was used to create economic cases for GB economic growth. Retail energy price forecasts are also provided. For 2019 a wider 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.

Commercial

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

Transport

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

- Rail – projections are applied to the electric rail demand based on stakeholder feedback, to illustrate different levels of rail transport electrification.

Other/Sundry

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

Peak Demands

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

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

The overlays to peak demand are:

- Electric vehicles: Based on the projected numbers, the potential user groups are assessed, how and when they could be charging (constrained and unconstrained), and data from recently published trials are incorporated. For 2019, new data from an innovation project (Development of GB Electric Vehicle Charging Trials)[47] was used to review and revise our modelling on home, workplace and public charging. Smart charging behaviour is assumed to differing degrees in all scenarios.
- Heat pumps: The number of heat pumps and heat demand, data from manufacturers, and trial within day profiles combined with performance statistics and historical weather trends are used to determine the electrical heat demand at peak. Thermal storage is assumed in the low carbon scenarios as part of the smart energy system and acts to reduce peak heat demands.
- Losses: As with annual demand, this is a function of total peak demand.
- Industrial & Commercial Demand Side Response: Created using desktop research and assumptions of future efficiency improvements, consumer engagement and information technology improvements.
- Domestic peak response – as with annual demand this starts with the smart meter roll-out numbers, project outcome data and perceived customer engagement rates. From this results a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

Calibration

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

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

Results

The results of the described methods provided are defined and shown in the Annex (Section A.4.1). For a more detailed description of the methodology and FES scenarios please refer to the FES document or its workbook[48]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

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

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

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

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

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:

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

Technology

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

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

Financial Markets

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

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

A.2.3 FES Plant Economics

This area is a key feed-in to the power generation backgrounds and explores economic viability and how a particular plant or group of plants could operate in the market now and in the future. The results of the analysis inform the transmission generation backgrounds, particularly plant closure profiles.

A.2.4 Project Status

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

A.2.5 Government Policy and Legislation

It is important that the power supply scenarios reflect Government policy and initiatives for particular generation projects and/or technology. This may be in the form of financial support for selected technologies that are targeted and developed, such as the low carbon technologies; nuclear, offshore wind, marine energy and CCS. Alternatively, it could be in the form of market-wide mechanisms 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 2019 power generation backgrounds are developed to both meet demand and to reflect the implementation of the GB Reliability Standard of 3 hours Loss of Load Expectation (LOLE) / year. In the early years of the FES study period, the generation backgrounds were driven by relatively more granular intelligence and therefore LOLE could potentially vary significantly year to year within this period. This can, for instance, be caused by plants without CM contracts staying open.

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

A.3 EMR/Capacity Assessment Development Projects Matrix

Table 34 lists all the proposed development projects and their respective scores. Based on the process described in Section 2.5.1, only projects 1-18 attracted high enough scores to qualify for this year's development phase. Table 35 shows the scoring matrix used for the prioritisation.

Following the initial prioritisation, projects 8, 11, 13 and 17 were deprioritised and the scope of projects 5, 7, 14, 15 and 16 were reduced in order to prioritise the consultation of project 12 and other work (e.g. projects 21 and 23). Project 24 was considered as part of FES. Project 34 was prioritised and handed over to National Grid ESO's innovation team to take it forward. Project 37 was prioritised and led by BEIS. Note that shaded projects either didn't score high enough or were deprioritised and therefore weren't progressed.

Table 34: Development Projects Matrix

Development Project Description	Impact	Effort*	Priority*	Difficulty level*	Data Difficulty	Total
1) Review DDM wind scaling parameter for Base Case, low and high wind sensitivities	2	-1	10	-1	-1	9
2) Full and transparent disclosure of the construction of National Grid's Base Case (PTE Recommendation 36)	1	-2	10	-1	-1	7

Development Project Description	Impact	Effort*	Priority*	Difficulty level*	Data Difficulty	Total
3) Stress period analysis to inform interconnector de-rating factor modelling.	3	-2	10	-2	-2	7
4) Review LOLE and wind / solar / storage EFCs for generation background in the light of the summer project on renewables in the CM	2	-2	10	-2	-1	7
5) To support the review of the GB Reliability Standard work, develop a better understanding of net-CONE implications of operational timeframe costs.	3	-2	10	-3	-2	6
6) Review and update wind power curves	2	-2	10	-1	-3	6
7) Provide support to and engagement with the BEIS 5-year review of GB reliability standard	3	-2	10	-2	-3	6
8) Improve historical demand time series for LOLE modelling	3	-3	10	-2	-3	5
9) Analyse how interconnector de-rating factors might be expected to change over time	1	-2	8	-1	-1	5
10) Initial analysis of Electralink data to calculate de-rating factors	3	-3	10	-2	-3	5
11) Develop a better understanding of how scarcity rent (price escalator) works in BID3	2	-2	9	-2	-3	4
12) Investigation of appropriate de-rating factors for renewable technologies potentially entering the Capacity Market.	3	-3	10	-3	-3	4
13) Re-assess the CM Rules definition of conventional plant availability which is based on peak transmission demand hours in winter	2	-2	6	-1	-1	4
14) Consider how we would develop de-rating factors for foreign generators that are on the other side of an interconnector	3	-3	10	-3	-3	4
15) Engage with the 5-year review of the CM to put in place adequate performance requirements and coordination procedures for duration limited storage	2	-3	10	-3	-3	3
16) Understand the multitude of EMR and FES modelling issues regarding collocation/hybrid sites	1	-3	10	-2	-3	3
17) Re-assess the definition of CM stress events as suggested by BEIS CM Review	2	-2	6	-2	-2	2
18) Review the impact of set aside strategic reserves in continental Europe on interconnector contribution to security of supply (PTE Recommendation 40)	2	-2	6	-2	-2	2
19) Consider duration-limits (if any) in the DSR and diesel generation technology types	2	-2	6	-1	-3	2
20) Estimate the range of potential impact of non-delivery and over-delivery of non-CM (e.g. renewable) capacity in the Base Case.	2	-2	6	-2	-3	1
21) Undertake review of developing a sequential version of the CA model. Also, to review Capacity Adequacy work and model provided to Ofgem.	1	-2	5	-2	-1	1
22) Undertake a historical analysis to determine the extent to which stress events on network have been due to combined events and to assess whether such combinations might arise again. (PTE Recommendation 39)	2	-3	6	-2	-3	0
23) Review Least Worst Regret process for future T-1 recommendations	3	-2	2	-2	-1	0
24) Investigate the evidence for selecting a wider sensitivity band for demand outturns for overall demand both using historical data and its own FES modelling, to confirm that its current approach is appropriate. (PTE	2	-2	2	-1	-2	-1

Development Project Description	Impact	Effort*	Priority*	Difficulty level*	Data Difficulty	Total
Recommendation 38)						
25) Analyse the impact of scarcity pricing on peak demand and also examine demand responses to high prices in markets (PTE Recommendation 29)	1	-2	6	-3	-3	-1
26) Review treatment of non-CM capacity in the DDM to better account for capacity in later years	2	-2	2	-1	-2	-1
27) Understand the best approach for storage peak load factor for demand forecasting work	2	-3	4	-3	-1	-1
28) Develop a synthetic load demand time series based on temperature/weather dependency	2	-3	2	-2	-2	-3
29) Consider using a margin range in future Winter Outlooks to accommodate modelling uncertainty in interconnection security of supply contribution	2	-2	2	-2	-3	-3
30) Develop a "net demand" version of the CA and DDM models, to avoid the use of an exogenous scalar applied to wind storage	2	-3	2	-2	-2	-4
31) Decide which risk metric is most appropriate for FES 2030 to be targeting - with multiple 10's of GW of wind solar and storage	2	-3	2	-3	-3	-5
32) Develop a methodology to de-rate large scale transmission-connected EV charging stations	2	-3	2	-3	-3	-5
33) Determine what de-rating factor should voltage reduction receive if it becomes an eligible form of CM capacity	2	-3	2	-3	-3	-5
34) Undertake a pro-active role in informing the public about the issues in maintaining security of electricity supply. Co-ordinate through the Energy Networks Association (ENA) or code group with support from Energy UK and Association of Distributed Energy (ADE) (PTE Recommendation 30)	1	-3	1	-3	-1	-5
35) Consider the range of additional forms of ‘latent capacity’ in addition to Recommendation 16 (Collect information on how Distribution Network Operators (DNOs) plan to respond to Demand Control orders to ensure security of supply). (PTE Recommendation 35)	1	-3	2	-3	-3	-6
36) Develop a proper demand time series shape for FES future security of supply modelling - at the moment we are using 2005-2017	1	-3	2	-3	-3	-6
37) BEIS, NG and Ofgem should urgently consider information strategy to cover a risk register showing activities where data is required, whether data exists and who hold it, impacts of data gaps, and access routes to release data and data processing requirements. (PTE Recommendation 37)	1	-3	1	-3	-3	-7

*represents total scores based on scorings provided by National Grid, BEIS and Ofgem. The individual score provided by each organisation was based on Table 35 below.

Table 35: Development Projects Scoring Matrix

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

Priority	1	3	5
Difficulty level	-1	-2	-3
Data difficulty	-1	-2	-3

A.4 Detailed Modelling Assumptions

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

A.4.1 Demand (annual and peak)

Table 36 shows the annual demand while Table 37 shows the peak demand used for the 4 FES scenarios and Base Case covering the next 15 years. All sensitivities use the same annual and peak demand as the Base Case (except for the high and low demand sensitivities where the peak demand is 2% above / below the Base Case peak demand).

Table 36: Annual Demand* by scenario

Annual Demand TWh	2019	2020	2021	2022	2023	2024	2025	2026
Base Case	306	306	305	304	303	303	315	315
Community Renewables	305	301	297	294	292	289	288	288
Two Degrees	305	303	302	300	300	299	300	300
Steady Progression	307	309	311	313	313	314	315	315
Consumer Evolution	307	307	308	307	308	307	307	306

Annual Demand TWh	2027	2028	2029	2030	2031	2032	2033	2034
Base Case	316	317	319	321	323	325	328	331
Community Renewables	288	291	295	300	308	316	324	332
Two Degrees	303	308	313	320	327	336	345	354
Steady Progression	316	317	319	321	323	325	328	331
Consumer Evolution	307	307	308	309	311	312	315	318

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

Table 37: Peak Demand* by scenario

Peak Demand GW	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Base Case	58.9	58.9	58.9	58.8	58.9	61.9	62.0	62.1
Community Renewables	58.8	57.7	57.1	56.5	56.2	56.0	55.7	55.3
Two Degrees	58.8	58.3	58.1	58.1	58.3	58.7	58.7	58.9
Steady Progression	59.2	60.0	60.5	60.9	61.4	61.9	62.0	62.1
Consumer Evolution	59.0	59.4	59.6	59.7	59.9	60.1	59.9	59.7

Peak Demand GW	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Base Case	62.2	62.4	62.7	63.0	63.3	63.7	64.2
Community Renewables	55.7	56.2	56.5	57.4	58.6	59.8	60.9
Two Degrees	59.9	61.1	62.3	63.8	65.2	66.9	68.4
Steady Progression	62.2	62.4	62.7	63	63.3	63.7	64.2
Consumer Evolution	59.6	59.6	59.6	59.8	60.0	60.1	60.4

*The definition of peak demand is unrestricted[50] GB National Demand plus demand supplied by distributed generation.

A.4.2 Generation Capacity Mix

Tables 38 to 42 show the generation mix (nameplate capacity at winter peak, excluding solar PV) for the 4 FES scenarios and Base Case from the DDM model. The Non-CM capacity shows increases in most years after 2019/20 but falls in some scenarios in 2027/28 due to the end of RO and CFD support for biomass conversion.

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

Table 38: Base Case generation capacity mix

Base Case Capacity Mix (GW)	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
CM eligible	67.9	69.4	64.4	62.9	62.6	65.8	66.8	68.2
Non-CM	31.6	32.1	35.8	34.9	36.7	37.6	40.2	43.5
Total peak capacity	99.5	101.5	100.1	97.9	99.4	103.5	107.0	111.7

Base Case Capacity Mix (GW)	27/28	28/29	29/30	30/31	31/32	32/33	33/34
CM eligible	70.0	71.9	71.8	70.2	70.6	71.2	72.2
Non-CM	43.1	45.2	49.4	53.1	54.7	55.3	55.4
Total peak capacity	113.1	117.1	121.3	123.3	125.3	126.5	127.6

Table 39: Community Renewables generation capacity mix

Community Renewables Capacity Mix (GW)	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
CM eligible	64.5	64.2	62.4	58.7	58.7	58.7	59.2	59.2
Non-CM	31.8	32.5	36.9	37.4	40.7	43.6	46.6	51.2
Total peak capacity	96.3	96.7	99.3	96.1	99.4	102.3	105.7	110.5

Community Renewables Capacity Mix (GW)	27/28	28/29	29/30	30/31	31/32	32/33	33/34
CM eligible	62.3	62.4	60.2	60.7	61.6	62.6	63.1
Non-CM	52.5	58.4	64.4	68.2	71.5	74.6	78.1
Total peak capacity	114.8	120.8	124.6	128.8	133.1	137.2	141.2

Table 40: Two Degrees generation capacity mix

Two Degrees Capacity Mix (GW)	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
CM eligible	67.8	67.3	64.4	62.3	62.2	65.3	65.6	65.9
Non-CM	31.6	32.6	38.1	38.9	42.7	46.1	50.3	57.6
Total peak capacity	99.4	99.9	102.5	101.2	104.8	111.5	115.8	123.6

Two Degrees Capacity Mix (GW)	27/28	28/29	29/30	30/31	31/32	32/33	33/34
CM eligible	68.7	69.3	70.4	70.7	69.6	68.6	67.6
Non-CM	60.5	62.4	64.8	67.2	71.4	76.0	81.0
Total peak capacity	129.2	131.7	135.1	137.9	141.0	144.6	148.6

Table 41: Steady Progression generation capacity mix

Steady Progression Capacity Mix (GW)	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
CM eligible	66.4	69.0	64.3	66.1	64.3	65.1	65.4	66.0
Non-CM	31.2	31.5	34.9	33.9	36.0	37.6	40.2	43.5
Total peak capacity	97.6	100.6	99.1	100.0	100.3	102.7	105.6	109.5

Steady Progression Capacity Mix (GW)	27/28	28/29	29/30	30/31	31/32	32/33	33/34
CM eligible	68.5	69.0	69.5	68.4	68.6	69.0	70.0
Non-CM	43.1	45.2	49.4	53.1	54.7	55.3	55.4
Total peak capacity	111.6	114.2	119.0	121.5	123.3	124.3	125.4

Table 42: Consumer Evolution generation capacity mix

Consumer Evolution Capacity Mix (GW)	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
CM eligible	78.4	79.2	77.3	77.5	77.8	78.3	78.3	80.0
Non-CM	30.9	31.7	34.5	33.4	35.0	36.5	37.4	40.5
Total peak capacity	109.4	110.9	111.8	110.8	112.8	114.8	115.6	120.4

Consumer Evolution Capacity Mix (GW)	27/28	28/29	29/30	30/31	31/32	32/33	33/34
CM eligible	68.5	69.0	69.5	68.4	68.6	69.0	70.0
Non-CM	43.1	45.2	49.4	53.1	54.7	55.3	55.4
Total peak capacity	111.6	114.2	119.0	121.5	123.3	124.3	125.4

A.4.3 CM-ineligible Capacity

Table 43, Table 44 and Table 45 give a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2020/21, 2022/23 and 2023/24. The total capacity is lower than the nameplate capacity shown in A.4.2 since it is de-rated. Please note that the capacities by technology may not sum to the total ineligible capacity due to rounding.

Table 43: Breakdown of De-rated CM ineligible capacity for 2020/21

Generation type	Capacity (GW)
Onshore Wind	2.5
Offshore Wind	2.0
Biomass	3.9
Autogeneration	0.9
Hydro	0.9
Landfill	0.5
Other	1.3
Total	**12.1**

Table 44: Breakdown of De-rated CM ineligible capacity for 2022/23

Generation type	Capacity (GW)
Onshore Wind	2.8
Offshore Wind	2.7
Biomass	4.0
Autogeneration	0.9
Hydro	1.0
Landfill	0.5
Other	1.6
Total	**13.4**

Table 45: Breakdown of De-rated CM ineligible capacity for 2023/24

Generation type	Capacity (GW)
Onshore Wind	2.8
Offshore Wind	2.9
Biomass	4.0
Autogeneration	0.9
Hydro	1.0
Landfill	0.5
Other	1.7
Total	**13.7**

A.4.4 Station Availabilities

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

Table 46 shows the station availabilities used for the 4 FES scenarios, Base Case and the High and Low availability sensitivities (rounded to the nearest %).

Table 46: Station availabilities by sensitivity

	Technology type	2020/21	2022/23	2023/24
CCGT	Low availability sensitivity	**87%**	**87%**	**87%**
	Base Case	**90%**	**90%**	**90%**
	High availability sensitivity	**93%**	**93%**	**93%**
Nuclear (Existing)				
	Low availability sensitivity	**74%**	**74%**	**74%**
	Base Case	**81%**	**81%**	**81%**
	High availability sensitivity	**88%**	**88%**	**88%**
Nuclear (New)		90%	90%	90%
Coal		86%	86%	86%
AD (incl CHP)		68%	70%	70%
Autogeneration		90%	90%	90%
Biomass Dedicated/Conv./CCS/ CHP		86%	86%	86%
EfW		86%	86%	86%
EfW CHP		74%	74%	74%
Gas CHP (large scale)		**As CCGT**	**As CCGT**	**As CCGT**
Gas CCS		**As CCGT**	**As CCGT**	**As CCGT**
Gas Turbine		95%	95%	95%
Geothermal (incl CHP)		86%	86%	86%
Hydro		90%	90%	90%
Landfill		59%	59%	59%
OCGT and Recip. Engines		95%	95%	95%
Oil		91%	91%	91%
Pumped storage*		95%	95%	95%
Sewage Gas		49%	49%	49%
Solar PV EFC		1%	2%	2%
Tidal and Wave		22%	22%	22%
Wind EFC		20%	21%	21%

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

Note the two sensitivities cover only the two most uncertain technologies: CCGT and Nuclear (existing) shown in bold in the table above.

A.4.4.1 Conventional Transmission Station Availabilities

Table 47 shows the station availabilities based on the mean of the last 7 winters (2012/13 – 2018/19) for each type of generation.

Table 47: Station Availabilities

Generation Type	Availability
CCGT	89.48%
OCGT	94.98%
Coal	85.81%

Nuclear	81.22%
Hydro	89.65%
Pumped Storage	95.08%
Oil *	91.26%

* based on the years for which data was available.

Previous comments[51] from BEIS's PTE stated that the availability of CCGT plant was low when compared to other markets with similar support mechanisms and recommended that National Grid ESO undertake analysis to benchmark CCGT and other technology availabilities from around the world.

Previously, National Grid ESO commissioned ARUP, in 2014, to produce a report on the availability of plant, particularly CCGTs, in markets that incentivise availability. For the main generation technologies of CCGT, OCGT, coal and nuclear, Arup provided an availability assumption. Table 48 shows the two views of availabilities.

Table 48: Availability Comparison

Generation Type	National Grid ESO	Arup
CCGT	89%	87% - 93%
OCGT	95%	94%
Coal	86%	87%
Nuclear (Existing)	81%	77%

Based on the international benchmark data provided in Arup's report and further discussions with BEIS and the PTE, the availabilities for each type of generation have been revised to the values as shown in Table 49.

Table 49: Availabilities Used

Generation Type	Availability
CCGT Pre 2020/21	89%
CCGT 2020/21+	90%
OCGT	95%
Coal	86%
Nuclear (Existing)	81%

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

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

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

National Grid ESO has to hold capacity in reserve in order to maintain system operability if a loss of generating capacity occurs. This capacity has to be accounted for in the LOLE calculation and is added to the peak demand assumptions. Table 50 shows the reserve requirement to cover the largest in-feed loss for each scenario. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held.

Table 50: Reserve to cover largest infeed loss by scenario

In Feed Loss MW	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Base Case	1500	1500	1500	1700	1000	1000	1000	1000
Community Renewables	1500	1600	1600	1800	1300	1300	1400	1500
Two Degrees	1500	1500	1700	1700	1100	1100	1100	2000
Steady Progression	1500	1500	1500	1600	1000	1000	1000	1000
Consumer Evolution	1500	1500	1500	1500	1100	1200	1200	1200

In Feed Loss MW	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Base Case	1000	1000	1900	1900	1900	1900	1900
Community Renewables	1500	2400	2400	2500	2500	2500	2500
Two Degrees	2000	2000	2000	1900	1900	1900	1900
Steady Progression	1000	1000	1900	1900	1900	1900	1900
Consumer Evolution	1300	1300	1300	2200	2200	2300	2300

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

A.5 Detailed Modelling Approach

Details for this section can be found in page 81 of ECR 2017.[52]

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

A.6 Storage De-rating Factor Data Assumptions

As reported in Sections 2.4.3.4 and 4.1, we have calculated the de-rating factors for duration limited storage in the 2019 ECR based on an updated view of storage durations and capacities. (see Table 51). Please note that given that this work was carried out before the storage capacity figures were finalised, the capacities in the table may differ slightly from the final values. In 2017, we ran an industry consultation[53] on the methodology and modelling assumptions for the new approach to de-rating the sub-categories of this technology type. The final de-rating factor number for each duration limited storage class sub-category is (amongst other modelling assumptions) influenced by each of the following methodology attributes:

- (EFC) The incremental Equivalent Firm Capacity (EFC) of a perfectly reliable storage unit (of each respective duration) and of a relatively small capacity added to the margin of a Base Case targeted at 3 hours LOLE, the GB Reliability Standard. The Base Case is set up to reflect the expected composition of the GB power system in each T-1 and T-4 target year in question. One key issue is that as indicated by our report to industry last year, then the assumption of the amount and composition of storage in the Base Case in each target year will influence the EFC of incremental storage units added thereafter – more shorter duration storage in the Base Case will tend to reduce the incremental EFC of storage units added thereafter. The assumptions in the 2019 ECR Base Case for the penetration of storage by capacity and duration are listed in Table 51 below. This year, there is more storage capacity overall projected in the T-1 and T-4 Base Case than last year (as the years have advanced by one, and it is assumed that storage penetration will increase in to the future), and also the durations are a slightly lower than what was assumed last year based on observations in the recent Capacity Market auctions, whereby 0.5 hour and 1-hour storage durations were primarily successful amongst the new build entrants. The capacities for the provisional T-3 auction have also been included in the table.
- (TA-PS) The technical breakdown parameter to be applied to the storage technology class overall, namely that which is calculated as the historical technical availability of pumped storage over the last 7 years' winter periods - calculated as 95.08% this year
- The histogram of stress event durations of the same Base Case, whereby all durations above that duration threshold which corresponds to longer than 95% of potential stress events shall receive the same de-rating factor of pumped storage (TA-PS), and those that are shorter than this duration will receive a derating factor equivalent to the product of the incremental EFC and the technical availability of the storage class overall i.e. namely (EFC)*(TA-PS).

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

Table 51: Base Case duration limited storage assumptions (near final)

Duration Category (Hours)	2020/21 T-1 Capacity (MW)	2022/23 T-3 Capacity (MW)	2023/24 T-4 Capacity (MW)
0.5	619	1,367	1,719
1	1,297	1,514	1,584
1.5	122	152	152
2	4	9	9
3	5	5	5
4	100	115	115
6	2,005	2,005	2,005
21	300	300	300
22	440	440	440
Total	**4,893**	**5,907**	**6,330**

Due to the increased storage capacity assumed in the Base Case and, in particular, the increased penetration of short duration storage of 1 hour or less, the de-rating factors in Table 8 have reduced since the 2018 ECR. In addition, the duration threshold corresponding to 95% of stress events has increased to 5 hours in the T-1 year and 5.5 hours in the T-3 and T-4 years showing 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.

A.7 Least Worst Regret

Details of Least Worst Regret approach and methodology can be found in page 87 of the 2017 ECR[54]

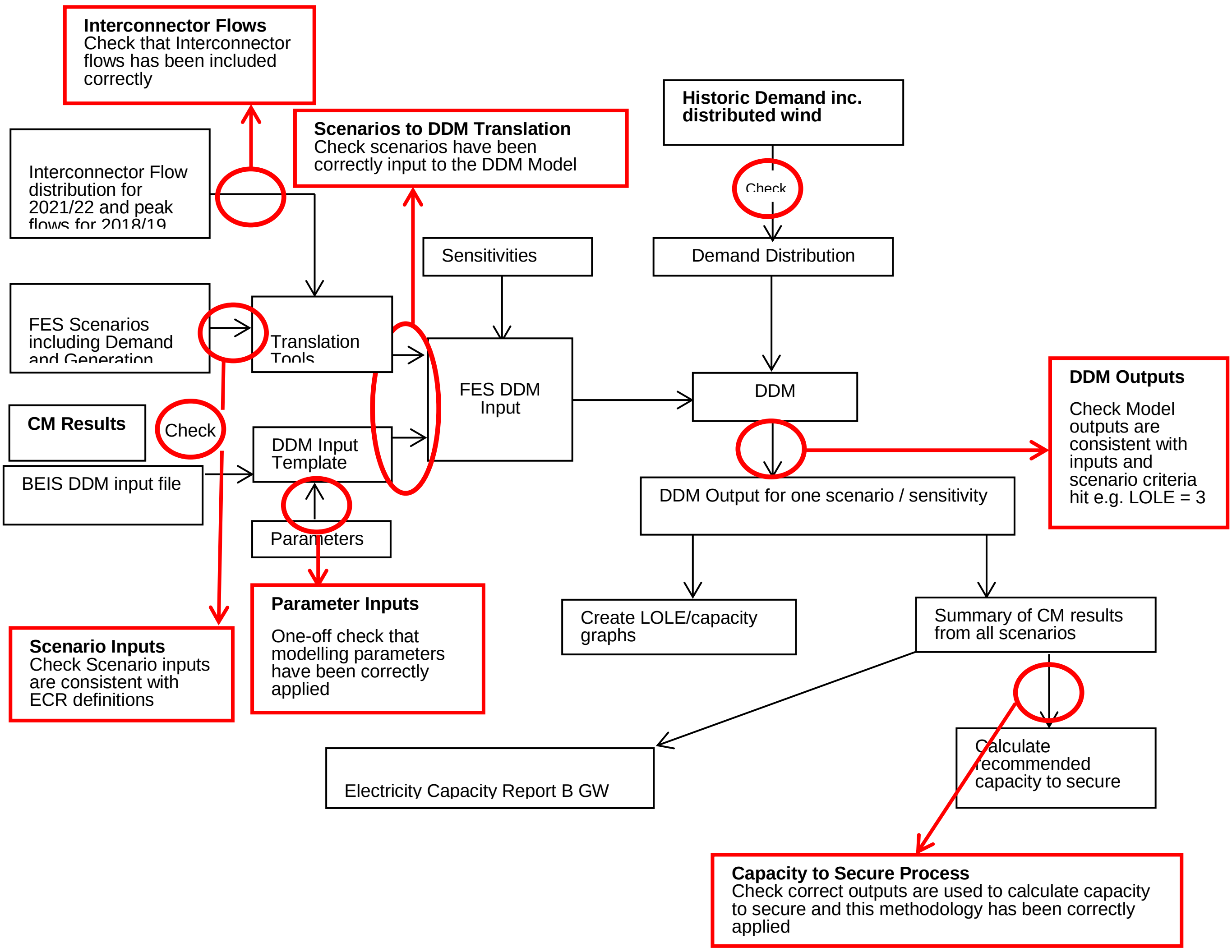
[54] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

A.8 Quality Assurance

When under taking any analysis, National Grid ESO looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid ESO has worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in house QA process[55]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have QA undertaken when that project 'stage gate' (such as inputting data in to a model) is met. This approach allows any issues to be quickly identified and rectified.

The high-level process and the points within the process where QA checks have been undertaken are shown in the following process diagram (Figure 39):

Figure 39: QA checks process diagram for each target year



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

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

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

Below is detailed QA process for each of these steps.

Interconnector flows

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

Scenario Inputs

The FES process is driven by extensive stakeholder engagement[56], workshops and bilateral meetings; this engagement leads to the creation of the scenarios. The constituent parts of the scenarios, for example electricity demand, are subject to internal challenge and review to ensure that they consistent and robust. Sign-off is then required at senior manager level and formal sign-off is then required from the SO Executive Committee. The assumption and outputs will be published in the annual FES document on 11th July 2019.

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

Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind

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

[56] http://fes.nationalgrid.com/media/1397/2019-stakeholder-feedback-document-published-v10-010319.pdf

Scenarios to DDM Translation

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

DDM Outputs

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

QA Check List Process

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

Capacity to Secure Process

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

Dynamic Dispatch Model (DDM)

In addition to checks described in above figure, the DDM has been reviewed and had QA performed a number of times including a peer review by Prof. Newbery and Prof. Ralph, a review of the code by PwC and internal reviews by BEIS.

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of the DDM for ECR. In previous years, the owners of the DDM, consultants Lane Clark & Peacock (LCP[57]), were asked to ensure that National Grid ESO was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between National Grid 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 concluded that National Grid 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 System Operator.

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

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